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California Energy Commission
Docket Unit
1516 Ninth Street
Sacramento, CA 95814-5512

Subject: **PALO VERDE SOLAR 1, LLC'S INITIAL COMMENTS ON THE STAFF ASSESSMENT/DRAFT ENVIRONMENTAL IMPACT STATEMENT DOCKET NO. (09-AFC-6)**

Enclosed for filing with the California Energy Commission is the original of **PALO VERDE SOLAR 1, LLC'S INITIAL COMMENTS ON THE STAFF ASSESSMENT/ DRAFT ENVIRONMENTAL IMPACT STATEMENT**, for the Blythe Solar Power Project (09-AFC-6).

Sincerely,

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STATE OF CALIFORNIA

Energy Resources
Conservation and Development Commission

In the Matter of: Application for Certification for the BLYTHE SOLAR POWER PROJECT	**DOCKET NO. 09-AFC-6** **PALO VERDE SOLAR 1, LLC'S INITIAL COMMENTS ON THE STAFF ASSESSMENT/DRAFT ENVIRONMENTAL IMPACT STATEMENT**

Palo Verde Solar 1, LLC (PVSI) hereby submits its initial comments on the Staff Assessment/Draft Environmental Impact Statement (SA/DEIS) published on March 11, 2010 for the Blythe Solar Power Project (BSPP). In preparation for the SA/DEIS workshop in April 2010, PVSI offers its initial comments ahead of the Workshop so that the parties can be the more productive in light of the modified scheduling order. In these comments, BSPP provides proposed resolution of issues to Staff and BLM for consideration.

Suggested additions are shown in ***bold italics*** and suggested deletions are shown in ~~strikethrough.~~

For clerical correction and ease to Staff and BLM, we are suggesting the following global corrections to descriptions of the various components of the project that are repeated throughout the SA/DEIS. These corrections, for the most part, reflect areas where the descriptions do not reflect supplemental information already provided to the CEC in the form of data responses or official Supplements, but also include project refinements and clarifications:

- Any reference to "applicants" should be replaced with "applicant" or PVSI.
- The disturbance area should be changed from 7,030 acres to 7,043 acres and will be revised accordingly to reflect the final transmission line route, temporary construction power line, telecommunication line and the paving of Black Rock Road.
- Construction water needs should be increased from 3,100 acre-feet/year (afy) to 4,100 afy.

This submittal includes three Attachments (Attachments 1, 2 and 3) to describe a number of relatively minor updates to the Project: Attachment 1 is a red line/strikethrough markup of the Project Overview provided in the SA/DEIS; Attachment 2 presents evaluations of the environmental implications of these modifications and Staff's final analysis should reflect these changes; and Attachment 3 contains comments on the Preliminary Determination of Compliance (PDOC).

EXECUTIVE SUMMARY

Page 2, Second to Last Paragraph

The BSPP is identified as four adjacent, independent units each with a generating capacity of 250 MW. The SA/DEIS should clarify that this capacity is a nominal rating as follows:

> The performance of each of the four 250 MW power blocks will vary with solar radiation and ambient temperature levels. At optimal solar radiation and low air-cooled condenser (ACC) back pressure (low ambient temperatures), the steam turbine-generator (STG) can produce 272 MW gross. As ambient temperature increases, the cooling effectiveness of the ACC decreases, causing the back pressure on the steam turbine to rise and, correspondingly, lowering steam turbine output. Parasitic loads (i.e., those loads required to operate the plant), also vary in relation to ambient temperature, due to the increasing power requirement for the ACC and plant auxiliary cooling equipment. At an ambient temperature of 96^{o} F, the STG can produce 264 MW and plant parasitic load is approximately 29 MW, providing a net-to-grid power block rating of approximately 235 MW. Conversely, on a cool winter day with optimal solar radiation, the STG can produce 272 MW, and the plant parasitic load will be approximately 28 MW for a net-to-grid power block rating of approximately 244 MW. By convention, therefore, an average "nominal" capacity of 250 MW was selected as being largely representative of unit capacity under most temperature ambient conditions.

PROJECT DESCRIPTION

Page B.1-2, HTF System

The originally proposed fired HTF heater will be replaced with an unfired HTF heat exchanger. The new heat exchanger will be of the shell and tube type and will utilize 165 psig saturated steam from the auxiliary boiler as the heating medium. The capacity of the auxiliary boiler will be 35 MMBtuU/hr, of which 25% will be used for overnight steam supply to the STG steam seals, reserving approximately 26.25 MMBtu/hr for HTF heating when needed on the coldest winter nights.

Page B.1-12, Section B.1.4.3, Transmission Line Route

This section of the SA/DEIS indicates that the transmission line route is not yet finalized. The route for the gen-tie line between the BSPP site and the SCE Colorado River Substation has been selected and is shown in Figure PD-1. The required biological resources and cultural resources surveys for this route are underway and results will be reported when they are available later this spring.

ALTERNATIVES

Page B.2-9, Sections B.2.4.1 and B.2.4.2, Project Objectives

Staff should include the following objective of the Project and this discussion and consider whether the alternatives carried forward meet that objective.

The state and federal governments are moving rapidly toward a policy of clustering renewable energy development within areas, or zones, rather than permitting that development to be spread across the State. Coequal goals in this effort are: minimizing environmental impact, maximizing renewable energy production, minimizing sprawl, and reducing infrastructure investment to bring the power to market thus reducing overall costs to ratepayers.

The Blythe Solar Power Project is located within an area that has been selected by two key planning efforts to be a priority area for renewable energy development based on the area's resource quality, transmission access, and lack of significant biological resources. Those two key planning efforts are the Renewable Energy Transmission Initiative, or RETI, and proposed Solar Energy Study Areas (SESAs) identified by the Department of Energy and Bureau of Land Management's Solar Energy Development Programmatic Environmental Impact Statement (PEIS) process.

The State's RETI process was initiated in 2007 and is focused on identifying renewable energy development zones and planning the transmission to access those zones. The SESA process within the PEIS is focused on designating zones in which renewable energy projects could be permitted on an expedited basis. Finally, the Desert Renewable Energy Conservation Plan (DRECP) process is focused on gathering data and mapping priority biological areas and wildlife movement corridors. Each of these planning efforts will ultimately be combined to provide the basis to implement a policy in which renewable energy development is concentrated in certain geographic areas.

In addition, co-locating multiple solar thermal power plants minimizes disturbance across the region. By co-location, there is an "economy of scale" that allows the design to utilize shared/common facilities for multiple power plants (e.g., offices, construction laydown areas, solar array assembly facilities, warehouses and maintenance facilities). Further, co-located facilities minimize regional disturbance to natural and visual resources by reducing the need for additional transmission corridors, and by reducing the need for other infrastructure such as water wells and/or water pipelines, natural gas pipelines, temporary laydown areas and temporary/permanent access roads that would be required if the units were developed at separate locations. Co-located facilities also consolidate impacts of lighting, noise, and human presence at a single location rather than introducing them to multiple environments. Finally, consolidated facilities also geometrically reduce edge effects compared to individual plants on separate sites. For the BSPP, boundaries with adjacent undisturbed areas is reduced by 50 percent (replacing four plants that each have a 4-mile outer perimeter, for a combined total outer perimeter of 16 miles, with four contiguous plants having a combined outer perimeter of 8 miles).

Page B.2-12, First Bullet

The SA/DEIS states that because the US Army Corps of Engineers (USACE) has not issued a finding of whether or not it would take jurisdiction over the ephemeral drainages under Section 404 of the Clean Water Act, Staff cannot conclude the project would comply with that act. While PVSI has submitted substantial data indicating that such ephemeral drainages are not "Waters of the United States", Staff could simply complete its analysis now, requiring a Section 404 permit be obtained from the USACE should the USACE ultimately be determined to have jurisdiction and require a permit. Staff has already determined the project impacts to these drainages under both CEQA and NEPA and therefore can require a simple condition of certification requiring PVSI to either obtain the 404 permit or provide proof that such a permit is not required. Therefore, in the unfortunate event that the USACE does not respond to PVSI's request for concurrence that the ephemeral drainages are not "Waters of the United States" prior to publication of the Addendum or Errata to the SA and the Final EIS (SAA/FEIS) PVSI requests Staff adopt such a condition in the SAA/FEIS.

Page B.2-12, Second Bullet

This bullet addresses Staff's view that the Project would result in cumulative residual impacts after mitigation of all direct and indirect impacts for all resources areas except Visual Resources, which Staff concludes is unmitigatable. Staff does not address the benefit of co-locating four solar thermal units which addresses the very fragmentation that Staff relies on to determine that the Project contributes to a cumulatively considerable impact with other future solar projects. In that regard, the BSPP has mitigated its impact by engaging in such co-location and avoiding further fragmentation. PVSI requests that Staff expand its analysis to document the benefit of such co-location.

B.2-35, Section B.2.7.2, Blythe Mesa Alternative

The SA/DEIS states that "No component of the project except for the transmission line would be greater than 70 feet." The Air Cooled Condensers will also be greater than 70 feet.

Page B.2-64 – B.2-65, Section B.2.8.2, Distributed Solar Technology, Project Objectives

In this Section the SA/DEIS indicates that the Andasol 1 power plant in Spain generates 50 MW on approximately 127 acres. The Applicant would like to clarify that the mirror area of Andasol 1 is approximately 127 acres, however, the power plant covers nearly 500 acres. Additionally, Andasol 1 is one of three co-located 50 MW solar thermal power plants developed and engineered by the Solar Millennium Group. As a 50 MW plant, Andasol 1 is not distributed generation.

In this section, the SA/DEIS concludes that distributed solar technology would meet the CEC's Project Objectives. The objectives that are controlling are the objectives of the applicant. PVSI could not deliver 1000 MW of competitive renewable energy to a utility through a distributed system which would require coordination with thousands of owners and an extremely complex system of transmission of electricity.

AIR QUALITY

Page C.1-1, Second Paragraph

The SA/DEIS uses a threshold of significance for fugitive emissions that is derived from the significance thresholds for a Prevention of Significant Deterioration (PSD) Permit. However, as Staff points out these thresholds clearly do not apply to the BSPP and therefore should not be used as thresholds of significance under either CEQA or NEPA. Specifically use of the PSD threshold for CEQA and NEPA purposes in this manner is not appropriate for a number of reasons:

- Fugitive emissions are not counted towards PSD applicability unless the source is one of the 28 listed source categories. Construction is not one of the listed categories. Thus, while PSD could apply to Project construction sources, the emissions evaluated for PSD applicability would not include fugitive dust.
- Based on the Project construction plan as proposed in the August 2009 AFC and subsequent CEC filings by the Applicant, Project construction emissions (without fugitive dust) do not exceed PSD thresholds.

PSD applicability is evaluated based on controlled emissions and the BSPP includes emission controls. Thus, it is inappropriate for Staff to speculate on the outcome of a PSD evaluation of a (hypothetical) unmitigated Project.

In Section C.1.3.4 Staff states that PSD thresholds would only apply to operations (we agree with this statement). Therefore, it is inconsistent to imply that PSD thresholds should be used as significance criteria for construction emissions under NEPA.

Page C.1-15 Project Emissions

The construction emissions summary tables on page C.1-16 need to be updated to reflect the Project engineering refinements described in Attachment 2. In addition, the second paragraph of text in this section should be modified to clarify the sources of emissions, as shown below.

> Combustion emissions would result from the off-road construction equipment, including diesel construction equipment used for site grading, excavation, and construction of onsite structures; ***off-road construction equipment used at the onsite batch plant***; and on-road vehicles, including heavy duty diesel trucks used to deliver materials, other on-road diesel trucks used during construction, and worker personal vehicles and pickup trucks used to transport workers to and from and around the construction site. Fugitive dust emissions would result from site grading/excavation activities; construction of power plant facilities, roads, and switchyard; ***the use of an onsite batch plant***; the installation of the new transmission line, the new gas pipeline, and the new onsite water pipelines; and vehicle travel on paved and unpaved roads. ***There will also be emissions associated with the use of the onsite fuel depot.***

Air Quality Table 6
BSPP Construction – Maximum Annual Emissions (lbs/day)

	NOx	VOC	CO	PM10	PM2.5	SOx
Onsite Construction Emissions						
Main Power Block (entire project)						
Off-road Equipment Exhaust	832.61	88.15	464.35	35.57	26.89	1.82
On-road Equipment Exhaust	27.77	2.33	14.63	1.34	1.23	0.04
Asphaltic Paving	--	0.00	--	--	--	--
Fugitive Dust from Paved Roads	--	--	--	6.06	2.76	--
Fugitive Dust from Unpaved Roads	--	--	--	614.07	61.44	--
Fugitive Dust from Construction Activities	--	--	--	246.38	76.35	--
Batch Plant Emissions	17.86	1.30	9.84	17.48	17.48	0.03
Fuel Depot		**3.50**				
Subtotal - Power Block Onsite Emissions	**878.24 ~~860.38~~**	**95.28 ~~90.48~~**	**488.82 ~~403.89~~**	**920.90 ~~903.42~~**	**186.15 ~~168.67~~**	**1.89 ~~1.86~~**
Power Block On-Road Equipment (offsite)	328.27	45.67	403.89	101.98	51.66	0.77
Access Road Construction (offsite)	211.84	24.20	92.78	114.92	39.87	0.45
Gas Pipeline Construction (offsite)	14.83	1.99	8.79	7.85	2.78	0.03
Transmissions Line Constriction (offsite)	13.67	1.55	15.81	8.30	3.02	0.03

Air Quality Table 7
BSPP Construction – Maximum Annual Emissions (ton/yr)

	NOx	VOC	CO	PM10	PM2.5	SOx
Onsite Construction Emissions						
Main Power Block (entire project)						
Off-road Equipment Exhaust	96.27	10.34	54.68	4.35	3.29	0.21
On-road Equipment Exhaust	3.45	0.3	1.84	0.14	0.13	0
Asphaltic Paving	--	0.01	--	--	--	--
Fugitive Dust from Paved Roads	--	--	--	0.68	0.31	--
Fugitive Dust from Unpaved Roads	--	--	--	68.77	6.88	--
Fugitive Dust from Construction Activities	--	--	--	26.95	8.29	--
Batch Plant Emissions	2.14	0.16	1.18	2.30	2.30	0.00
Fuel Depot		0.64				
Subtotal - Power Block Onsite Emissions	101.86 ~~99.72~~	11.45 ~~10.66~~	57.70 ~~56.51~~	103.19 ~~100.89~~	21.20 ~~18.90~~	0.22
Power Block On-Road Equipment (offsite)	34.6	5	43.97	11.19	5.71	0.08
Access Road Construction (offsite)	4.66	0.53	2.04	2.53	0.88	0.01
Gas Pipeline Construction (offsite)	0.64	0.09	0.38	0.34	0.12	0
Transmissions Line Constriction (offsite)	0.87	0.1	1.1	0.63	0.23	0

Page C.1-16, Project Operation

As noted above under Project Description, the BSPP will use an HTF heat exchanger instead of a fired HTF heater, where the Project's boiler will provide the needed heat. Emissions implications of replacement of the HTF heater and increasing the operation hours and load of the Project's boiler are addressed in Attachment 2. Other changes to the list of operational equipment found in this section should be revised as shown below to reflect the engineering refinements discussed in Attachment 2. Text of the SA/DEIS on these pages should be revised to reflect these changes.

Stationary emissions sources (total equipment for all four power blocks):

- Auxiliary Boiler (4 total): 35 MMBtu per hour natural gas-fired auxiliary boiler used for start up. Daily operation would be limited to 15 hours per day at 25% load and ~~two~~ 12 hours per day at full load. Annual operation would be limited to ***5,100*** ~~5,000~~ hours (***600*** ~~500~~ hours at a full load and 4,500 hours at 25% load).

- ~~HTF Heater (4 total): 35 MMBtu per hour natural gas fired HTF heater used for freeze protection. The HTF heaters would be limited to 10 hours per day and 500 hours per year.~~

- Two-cell auxiliary wet cooling tower (4 total two-cell units): 6,034 gallons per minute cooling tower to remove residual heat from balance of plant (BOP) equipment. Each cooling tower would have a maximum run time of ***24*** ~~16~~ hours per day and ***8,760*** ~~3,700~~ hours per year.

- ***One Fuel Depot consisting of two, 2000 gallon on-road vehicle diesel tanks, two 8,000-gallon off-road vehicle diesel tanks, one 500-gallon gasoline tank, and a wash water holding tank. The fuel farm would include secondary spill containment, a covered maintenance area, also with secondary containment, and a concrete pad for washing vehicles.***

Page C.1-17, Mobile Emission Sources

The SA accurately describes a mirror washing schedule of 18 events per year (from the AFC). As described in the Data Responses, the Project plans have since been clarified to include 78 wash events per year. Modified emissions calculations are included in Attachment 2.

Page C.1-18 Project Operation, Air Quality Table 8 and Air Quality Table 9

The emissions shown in Tables 8 and 9 should be revised as shown below to reflect the engineering refinements discussed in Attachment 2.

Air Quality Table 8
BSPP Operations - Maximum Daily Emissions (lbs/day)

	NOx	VOC	CO	PM10	PM2.5	SOx
Onsite Operation Emissions						
Auxiliary Boilers	20.61 ~~8.94~~	9.28 ~~4.03~~	69.69 ~~30.24~~	18.55 ~~8.05~~	18.55 ~~8.05~~	0.50 ~~0.22~~
~~HTF Heater~~	~~15.55~~	~~7.00~~	~~52.59~~	~~14.00~~	~~14.00~~	~~0.38~~
Emergency Fire Pump Engines	7.53	0.40	6.87	0.40	0.40	0.01
Emergency Generators	117.39	6.18	66.94	3.86	3.86	0.12
Auxiliary Cooling Towers	---	---	---	2.90 ~~1.93~~	2.90 ~~1.93~~	---
HTF Vents	---	6.00	---	---	--	---
HTF Piping Fugitives	---	17.51	---	---	--	---
Onsite Maintenance Vehicles	2.25 ~~2.36~~	0.23 ~~0.24~~	1.34 ~~1.27~~	809.84 ~~672.33~~	81.06 ~~67.31~~	0.02
Fuel Depot	---	0.48	---	---	--	---
Subtotal of Onsite Emissions	**147.78 ~~151.78~~**	**40.08 ~~41.36~~**	**144.84 ~~157.91~~**	**835.55 ~~700.57~~**	**106.77 ~~95.55~~**	**0.66 ~~0.76~~**
Offsite Emissions						
Delivery Vehicles	8.3	0.61	2.32	0.62	0.44	0.01
Employee Vehicles	4.72	4.94	47.02	9.74	4.56	0.07
Subtotal of Offsite Emissions	**13.02**	**5.55**	**49.34**	**10.36**	**5.00**	**0.08**
Total Maximum Daily Emissions	**160.80 ~~164.8~~**	**45.63 ~~46.91~~**	**194.18 ~~207.25~~**	**845.91 ~~710.93~~**	**111.77 ~~100.55~~**	**0.74 ~~0.84~~**

Air Quality Table 9
BSPP Operations - Maximum Annual Emissions (tons/yr)

	NOx	VOC	CO	PM10	PM2.5	SOx
Onsite Operation Emissions						
Auxiliary Boilers	1.34 ~~1.26~~	0.60 ~~0.57~~	4.54 ~~4.27~~	1.21 ~~1.14~~	1.21 ~~1.14~~	0.03
~~HTF Heater~~	~~0.39~~	~~0.18~~	~~1.31~~	~~0.35~~	~~0.35~~	~~0.01~~
Emergency Fire Pump Engines	0.19	0.01	0.17	0.01	0.01	0.0003
Emergency Generators	2.93	0.15	1.67	0.10	0.10	0.031
Auxiliary Cooling Towers	---	---	---	2.90 ~~0.22~~	2.90 ~~0.22~~	---
HTF Vents	---	0.60	---	---	--	---
HTF Piping Fugitives	---	3.20	---	---	--	---
Onsite Maintenance Vehicles	2.25 ~~0.14~~	0.23 ~~0.01~~	1.34 ~~0.08~~	809.84 ~~42.77~~	81.06 ~~4.28~~	81.06 ~~0.05~~
Fuel Depot		0.09				
Subtotal of Onsite Emissions	**4.68 ~~4.92~~**	**6.52 ~~4.72~~**	**6.52 ~~7.52~~**	**~~74.54~~ 44.59**	**~~9.12~~ ~~6.10~~**	**0.04 ~~0.05~~**
Offsite Emissions						
Delivery Vehicles	1.52	0.11	0.42	0.12	0.08	0.00
Employee Vehicles	0.86	0.90	8.58	1.78	0.83	0.01
Subtotal of Offsite Emissions	8.3 2.38	0.61 1.01	2.32 9.00	0.62 1.90	0.44 0.91	0.01 0.01
Total Maximum Daily Emissions	7.06 7.30	5.69 5.73	15.53 16.52	76.44 46.49	10.03 7.01	0.05 0.06

Page C.1-23, Construction Impacts and Mitigation, Air Quality Table 11

The summary of modeling results shown in Table 11 should be revised as shown below to reflect the engineering refinements discussed in Attachment 2. Because all of the modeled impacts have changed, for clarity, a completely revised table is provided below; the table as it appears in the SA/DEIS should be replaced in its entirety.

Air Quality Table 11
Project Operation Emission Impacts

Pollutant	Averaging Period	Concentrations				
		AERMOD Result (μg/m³)	Ambient Background[2] (μg/m³)	Total [3] (μg/m³)	CAAQS (μg/m³)	NAAQS (μg/m³)
NO_2 [1]	1-hr CAAQS	168.5	174.9	343.4	339	--
	1-hr NAAQS	178.7	N/A	178.7	--	188
	Annual	0.896	22.6	23.5	57	100
CO	1-hr	267.6	2,645	2,912.6	23,000	40,000
	8-hr	86.5	1,035	1,121.5	10,000	10,000
PM10	24-hr	22.3	162.0	184.3	50	150
	Annual	2.7	30.0	32.7	20	--
PM2.5	24-hr	2.9	27.0	29.9	--	35
	Annual	0.8	10.6	11.4	12	15
SO_2	1-hr	7.4	503.0	510.4	665	--
	3-hr	3.1	434.9	438.0	--	1,300
	24-hr	0.8	99.6	100.3	105	365
	Annual	0.1	5.2	5.3	--	80

[1] Modeled NO_2 concentrations as determined with the OLM. See section 3.5 for discussion of modeling for 1-hour NO_2 NAAQS.

[2] From Table 5.2-33 of the BSPP AFC. These values correspond to the highest monitored values from 2005 – 2007, except for PM2.5, which is the 98th percentile value over three years for the Indio, California monitoring site.

[3] Modeled concentration plus ambient background.

In the summary discussion of results following this table in the SA/DEIS, on Page C.1-23, paragraph 2, the conclusions should be revised as shown below:

> Staff also notes that the maximum background 1-hour NO_2 concentration, determined from a Palm Springs monitoring station, is very conservative both due to its proximity with the South Coast Air Basin (Los Angeles Metropolitan Area), and due to it being a single maximum value that would almost certainly not correspond to the same time period as the maximum modeled concentration. The applicant performed a review of the modeled concentrations versus actual hourly NO_2 background concentrations from the Palm Springs monitoring station and found that no exceedances of the 1-hour NO_2 standard were determined. The highest total hourly NO_2 concentration value found using the three highest modeled concentration values was ~~218~~ ***188*** μg/m³, only ~~64~~***56***% of the standard.

Page C.1-23, Third Paragraph Operation, Modeling Analysis

In this section, Staff concludes: “however, in light of the existing PM10 and ozone non-attainment status for the project site area, staff considers the operation NOx, VOC, and PM emissions to be potentially CEQA significant and recommends that the off-road equipment NOx and VOC emissions be mitigated pursuant to CEQA.” PVSI disagrees that any new emissions of non-attainment pollutants/precursors are automatically “significant” under CEQA.

For example, with respect to PM10 emissions, PVSI provided an analysis regarding the Project’s effect on the background PM10 levels to determine if the project is likely to cause or contribute to a violation of an ambient air quality standards. The current status of this part of the Mojave Desert Air Basin as non-attainment for PM10 is because of natural conditions, i.e., high winds rather than local industrial sources. Although the area is currently designated non-attainment for PM10, PVSI demonstrated that the BSPP will reduce existing wind blown fugitive dust emissions that are the source of current air quality problems. PVSI’s modeling of the BSPP’s PM10 emissions shows that the BSPP does not cause an exceedance of the applicable ambient air quality standards. It is only when added to the background concentrations, which currently exceed the standards that the result is over the standard. Therefore, the fact that the background concentrations will be lower once the BSPP is operating is relevant. A thorough evaluation was provided to Staff in January 2010 in response to DR-AIR-2 that quantified the substantial reduction in the baseline emissions that would occur with project implementation, Staff neglected to consider the reduction in PM10 from wind erosion in its analysis.

For these reasons, the PVSI does not agree with Staff’s conclusion that the BSPP will have significant air quality impacts simply because it emits nonattainment pollutants.

Pages C.1-25 – 27, Operation Mitigation

It is no longer necessary to include the HTF heaters in this section.

In the 3rd bullet on page C.1-26, Staff suggests that PVSI’s proposed electric vehicles as mitigation. PVSI did not propose such mitigation, and because other applicants have found the use of electric vehicles in the existing solar fields to be not feasible, such mitigation is not warranted. Further, the Conditions of Certification do not list electric vehicles as mitigation hence PVSI requests that references to this mitigation be deleted from this section.

At the top of page C.1-27, Staff proposes a leak detection and repair (LDAR) program for the HTF piping and system. This requirement goes well beyond current, accepted industry design practice and therefore LDAR is unnecessary for the BSPP. PVSI believes daily inspections and recording the amount of HTF replaced are more than sufficient for this system. An LDAR program is a relatively costly program that is without demonstrated control effectiveness in a solar field application. HTF is an expensive fluid and thus it is in PVSI’s best interest to minimize leaks without a requirement for LDAR monitoring and reporting. Implementation of an LDAR program would cause emissions from additional vehicle use for inspections and use of a manlift to reach many of the components. Further, the MDAQMD has no rule that would require LDAR for this type of project and MDAQMD has not requested LDAR for the BSPP.

Based on this reasoning, we have proposed changes to Condition of Certification AQ-SC9 shown later in these comments to remove the LDAR requirements related to monitoring leaks.

Page C.1-28, Second and Third Paragraph, PM2.5 Impacts

In this section, Staff discusses NOx and SOx contribution to PM2.5 formation. The discussion includes information regarding the potential affect of ammonia available in the ambient environment to participate in conversion of the precursors to PM2.5. However, since the discussion states that no actual data are available to make a determination in this region, this aspect of the discussion is speculative, inconclusive and unnecessary and hence should be revised or deleted.

Page C.1-42, Section C.1.10, Noteworthy Public Benefits

This section should be expanded to acknowledge that the BSPP would provide regional air quality benefits by displacing other conventional fossil fueled generation including the least efficient and highest polluting facilities. The Project is an instrumental part of California's commitment to combating climate change and reducing dependence on fossil fuels.

Renewable energy facilities, such as BSPP, are needed to meet California's mandated renewable energy goals. While the local area air quality public benefit from reducing regional PM10 background resulting from the proposed project is difficult to quantify, it would indirectly reduce criteria pollutant emissions within the Southwestern U.S. by reducing fossil fuel–fired generation. These goals are discussed further below:

Greenhouse Gas Emissions Reduction

The electricity generated by each nominal 250 MW unit of the Blythe Solar Power Project will offset the emission of two hundred thousand tons of greenhouse gasses in the electricity sector annually, which is equivalent to removing 35,000 cars from of the road each year.[1] The AB 32 Scoping Plan estimated that an electricity portfolio that is comprised one full third by renewable energy resources in 2020 would reduce statewide greenhouse gas emission by 21.3 million metric tons.

33% RPS by 2020

The Renewable Energy Transmission Initiative estimates that the renewable net short to achieve 33% renewable by 2020 is approximately 60,000 gigawatt-hours in 2020. The electricity produced by each nominal 250 MW plant will contribute 1% to this overall total goal in 2020.

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[1] This estimate is based off of WECC CAMX egrid emissions for the entire grid. Compared to a baseload natural gas plant, the offset is higher – about one-quarter megaton and 40,000 cars. Compared to a gas fired peaker, the offset is even higher – about 300,000 tons and more than 50,000 cars off the road each year.

Resource Adequacy Contribution

Utilities are currently required to procure 115% of their peak load under resource adequacy rules. It is further expected that 100% of the project will count towards Southern California Edison's resource adequacy requirements.

Offset of criteria pollutants

The electricity generated by each BSPP nominal 250 MW unit would offset the emission of 170 tons of oxides of nitrogen and 146 tons of sulfur dioxide annually if produced by a conventional, fossil-fueled power plant..

Pages C.1-42 and 43, Condition of Certification AQ-SC3

Condition of Certification AQ-SC3 requires that the Air Quality Construction Mitigation Plan (AQCMP) prevent all fugitive plumes from leaving the Project. This requirement presumes that a dust plume leaving the site is a significant impact. This is not the correct threshold of significance as the mere existence of a plume is in and of itself is not an impact. PVSI requests the following modification to set a reasonable standard that can be achieved during construction activities in the desert environment.

In addition, PVSI proposes a modification to Item b. of the Air Quality Construction Mitigation Plan to clarify that it can use a soil stabilizer that can also prevent weed growth during construction as long as the soil stabilizer would not impact off-site vegetation within areas that will not be disturbed during construction.

AQ-SC3 Construction Fugitive Dust Control: The AQCMM shall submit documentation to the BLM's Authorized Officer and CPM in each Monthly Compliance Report that demonstrates compliance with the Air Quality Construction Mitigation Plan (AQCMP) mitigation measures for the purposes of minimizing fugitive dust emission creation from construction activities and preventing all fugitive dust plumes from ~~leaving the project~~ ***impacting offsite sensitive receptors or interfering with traffic***. Any deviation from the AQCMP mitigation measures shall require prior BLM Authorized Officer and CPM notification and approval.

b. All unpaved construction roads and unpaved operational site roads, as they are being constructed, shall be stabilized with a non-toxic soil stabilizer or soil weighting agent that can be determined to be as efficient as or more efficient for fugitive dust control than ARB approved soil stabilizers, and that shall not increase any other environmental impacts including loss of vegetation ***to undisturbed offsite areas***. All other disturbed areas in the project and linear construction sites shall be watered as frequently as necessary during grading; and after active construction activities shall be stabilized with a nontoxic soil stabilizer or soil weighting agent, or alternative approved soil stabilizing methods, in order to comply with the dust mitigation objectives of Condition of Certification **AQ-SC4**. The frequency of watering can be reduced or eliminated during periods of precipitation.

Pages C.1-45 and 46, Condition of Certification AQ-SC5

Condition of Certification AQ-SC5 provides for requirements to reduce emissions from diesel fired construction equipment, some of which are very onerous for a construction project of this scope. PVSI requests the following modifications to the amount of idle time permitted (Item b.2) and the number of days that construction equipment can be on site before the equipment is required to meet Tier 3 standards (Item e).

b. 2. The construction equipment is intended to be on site for ~~5~~ ***10*** days or less.

e. All diesel heavy construction equipment shall not idle for more than ~~five~~ ***ten*** minutes. Vehicles that need to idle as part of their normal operation (such as concrete trucks) are exempted from this requirement.

Page C.1-47, Condition of Certification AQ-SC7

Condition of Certification AQ-SC7 requires that the Operations Dust Control Plan prevent all fugitive plumes from leaving the project. This requirement presumes that a dust plume leaving the site is a significant impact. This is not the correct threshold of significance as the mere existence of a plume is in and of itself not an impact. PVSI requests the following modification to set a reasonable standard that can be achieved during activities in the desert environment.

In addition, PVSI proposes a modification to the condition specifying the use of non-toxic soil stabilizers to clarify that it can use a soil stabilizer that can also prevent weed growth during operation as long as the soil stabilizer would not impact off-site vegetation within undisturbed areas.

AQ-SC7 The project owner shall provide a site Operations Dust Control Plan, including all applicable fugitive dust control measures identified in the verification of **AQSC3** that would be applicable to minimizing fugitive dust emission creation from operation and maintenance activities and preventing all fugitive dust plumes from ~~leaving the project site~~ ***impacting offsite sensitive receptors or interfering with traffic***; that:

The site operations fugitive dust control plan shall include the use of durable non-toxic soil stabilizers on all regularly used unpaved roads and disturbed offroad areas, or alternative methods for stabilizing disturbed off-road areas, within the project boundaries, and shall include the inspection and maintenance procedures that will be undertaken to ensure that the unpaved roads remain stabilized. The soil stabilizer used shall be a non-toxic soil stabilizer or soil weighting agent that can be determined to be as efficient as or more efficient for fugitive dust control than ARB approved soil stabilizers, and that shall not increase any other environmental impacts including loss of vegetation ***to undisturbed offsite areas***.

Page C.1-48, Condition of Certification AQ-SC9

As discussed above for Page C.1-27, PVSI disagrees with the requirement for an LDAR program as outline in items B, C, D, E and G of AQ-SC9. LDAR programs are typically reserved for oil refineries and chemical plants characterized by high pressure, high temperature streams of highly volatile organic liquids and gases. These conditions do not exist in this solar thermal plant; the HTF used in this plant has a low volatility, is used in low pressure piping, and although the operating temperature is 750°F, the temperature is relatively low when compared to the material's boiling point. PVSI expects that performing visual inspection of the solar field on a regular basis and recordation of the amount of HTF replaced in the system will be an adequate method to spot HTF leaks. If leaking, HTF will be visible as a mist or leaks dripping on the ground, and hence an instrumented monitor to detect invisible gases such as one would use in a refinery is not necessary. The LDAR program required by this condition is not cost-effective and has not been demonstrated to reduce emissions in solar field applications. Therefore, PVSI requests deletion of items B, C, D, E, and G in AQ-SC9.

PVSI also disagrees with the AQ-SC9, item H, requirement for pressure sensing equipment in the HTF loops to detect major ruptures. This requirement goes well beyond current, accepted industry design practice. Leak detection at solar thermal plants is currently accomplished by employing visual inspection throughout the solar field on a daily basis, which would detect small leaks occurring at ball joints or other connections. PVSI does not believe there is an adequate leak detection system currently available that employs pressure sensing devices on such a large volume system. The pressure decay would likely be slow after a failure so the presumption of quick action of any isolation valve is probably incorrect. Depending on where the leak is located, the header pressure will continue to supply pressure to the loops so the pressure sending system may not be able to detect it. Regardless, operators must inspect everything daily, and a mechanical integrity program will be in place at the BSPP that is aimed at preventing such leaks.

PVSI proposes incorporating the proven concept of "Leak before Break" which is accepted by the U.S. Nuclear Regulatory Commission and the German reactor safety commission. It has been shown that unstable crack growth in qualified piping would not occur or cause catastrophic leaks. This approach reasonably concludes that catastrophic breaks and leaks are of very low probability for the following reasons:

1. The HTF piping is of stainless and carbon steel construction with high integrity and strength characteristics that are not susceptible to unstable crack propagation or catastrophic failure. Cracks do not propagate rapidly, if at all.
2. HTF piping is certified to ensure proper material properties, predictable characteristics, and manufacturing integrity.
3. PVSI will design to the appropriate code, including adherence to seismic requirements.
4. HTF piping will be all welded construction using qualified welding procedures, qualified welders and materials.
5. The HTF system will be hydrostatically tested and inspected prior to operation.

6. The HTF system is not susceptible to corrosion, high fatigue, water hammer, or creep.
7. Temperatures and pressures in the HTF system are moderate (e.g., not in the creep range).
8. PVSI is committed by AQ-SC9 to inspections of relief valves; control devices, etc. once every operating period and will also inspect the HTF piping in a similar manner and frequency.
9. HTF is not hypergolic, pyrophoric, nor listed as a hazardous material, and the auto ignition temperature is 612 degrees C, hence, small leaks will not affect public safety. We are committed by AQ-SC9 to an inspection program and logging of HTF replacement quantities.

In the current system design, an HTF leak would occur slowly, and would be quickly detected by the facility's daily inspection program. Such leaks would be repaired immediately before any large leak or failure can occur. Therefore, we propose the following changes to Condition AQ-SC-9

AQ-SC9 The project owner shall establish an inspection and maintenance program to determine, repair, and log leaks in the HTF piping network and expansion tanks. Inspection and maintenance program and documentation shall be available to the CPM ***and AO*** upon request.

Verification: The project owner shall establish an inspection and maintenance ***plan and program*** that at a minimum include the following:

A. All pumps, compressors and pressure relief devices (pressure relief valves or rupture disks) shall be electronically, audio, or visually inspected once every operating period.

~~B. All accessible valves, fittings, pressure relief devices (PRDs), hatches, pumps, compressors, etc. shall be inspected quarterly using a leak detection device such as a Foxboro OVA 108 calibrated for methane.~~

~~C. VOC leaks greater than 100-ppmv shall be tagged (with date and concentration) and repaired within seven calendar days of detection.~~

~~D. VOC leaks greater than 10,000-ppmv shall be tagged and repaired within 24-hours of detection.~~

E. ~~The project owner shall maintain a log of all VOC leaks exceeding 10,000-ppmv, including location, component type, and repair made.~~

F. The project owner shall maintain record of the amount of HTF replaced on a monthly basis for a period of five years.

G. Any detected leak exceeding 100-ppmv and not repaired in 7-days and 10,000-ppmv not repaired within 24-hours shall constitute a violation of the District's Authority to Construct (ATC)/Permit to Operate (PTO).

H. ~~Pressure sensing equipment shall be installed that will be capable of sensing a major rupture or spill within the HTF network.~~

The inspection and maintenance plan shall be submitted to the CPM for review and approval at least 30 days before taking delivery of the HTF. The project owner shall make the site available for inspection of HTF piping Inspection and Maintenance Program records and HTF system equipment by representatives of the District, ARB, and the ~~Energy Commission~~ ***CPM and the AO.***

Section C.1.11.2, District Conditions

This section contains the District-required conditions. Generally, these conditions mirror the conditions set forth in the Preliminary Determination of Compliance (PDOC). PVSI submitted comments to the MDAQMD in February 2010 and we request that those comments be incorporated in the Final DOC and incorporated by the Staff; thus we have not repeated those comments herein (See Attachment 3). However, the proposed engineering changes discussed in Attachment 2 require that additional changes to the Conditions of Certification be made. Comments beyond those provided to the MDAQMD are provided below.

Page C.1-50, Condition AQ-5

Due to the change in hours of operation in the Project refinements described in Attachment 2, the fuel requirement of the auxiliary boiler will change, and Condition AQ-5 should be revised as follows:

AQ-5 The equipment shall be operated only on PUC pipeline quality natural gas and shall be equipped with a non-resettable fuel meter. Fuel used shall not exceed:

a. ***155*** ~~54,166,125~~ million cubic feet of natural gas per rolling twelve months; and:

b. ***441,667*** ~~191, 191,665~~ cubic feet of natural gas per calendar day.

<u>**Verification**</u>**:** The project owner shall submit to the CPM the boiler fuel use data demonstrating compliance with this condition as part of the Annual Operation Report (**COMPLIANCE-7**)

Pages C.1-50 and C.1-53, Conditions AQ-6 and AQ-14

These conditions require retention of an operations log for a period of five years. Other conditions require records retention for other periods, some shorter, some longer. To simplify recordkeeping, the Applicant requests that retention of all air quality-related records be for the same period; we recommend three years. AQ-6 and AQ-14 should be modified as shown below:

AQ-6 The project owner shall maintain an operations log for this equipment on-site and current for a minimum of ~~5~~***three (3)*** years, and said log shall be provided to District personnel on request. The operations log shall include the following information at a minimum:

AQ-14 The project owner shall maintain an operations log for this equipment on-site and current for a minimum of ~~five (5)~~***three (3)*** years, and said log shall be provided to District personnel on request. The operations log shall include the following information at a minimum:

Pages C.1-52 – 53, Conditions AQ-9 through AQ-16 (HTF Heater)

PSVI has determined that the HTF heater will no longer be needed for the project, and that a heat exchanger will be used instead. Consequently, Conditions AQ-9 through AQ-16 can be deleted from the SA/DEIS. The removal of the HTF heater from the Project is described in Attachments 1 and 2.

Page C.1-55, AQ-28

This Condition requires recordkeeping for ullage vent emissions monitoring for the life of the project. This is unnecessarily burdensome with no corresponding air quality benefit. PVSI requests that requests that this Condition be revised to require ullage vent emissions recordkeeping for the first five years of operations, with decisions on extension of this documentation to be made by the CPM and AO at that time.

Page C.1-57 and C.1-59, AQ-40 and AQ-49

Staff has added additional requirements to the verification beyond those contained in the PDOC. These requirements should be deleted and this condition should mirror the final version of the condition contained in the Final DOC.

Page C.1-61, Section C.1.12

In the conclusions presented in this section, Staff restates as bullet point #1 that construction PM10 emissions in excess of PSD emissions thresholds could be considered a significant impact. However, this is inconsistent with the listed NEPA significance criteria that states PSD thresholds only apply to operations emissions, and hence this bullet point should be deleted.

Bullet point #6 indicates that Staff found it necessary to propose an LDAR program (AQ-SC9) in order to ensure that emissions from HTF leaks were adequately controlled. As noted above, PVSI disagrees with the need for this program, and hence this bullet point should be deleted.

BIOLOGICAL RESOURCES

Page C.2-19, Functions and Values of Ephemeral Drainages/Waters of the State

This section states that Staff agrees with PVSI's analysis of functions and values for Waters of the State. The SA/DEIS accurately represents the Applicant's analysis. However, it should be noted that all functions and values were determined qualitatively based upon federal guidance and methodology (which is outlined in the Jurisdictional Delineation Report submitted as part of the August 2009 AFC submittal). Additionally, the qualitative functions and values of swales which support Creosote Bush -Big Galleta Grass Association were also included based upon the request of the CDFG.

Page C.2-28, Desert Tortoise Habitat

The last paragraph at the bottom of the page concludes that the there are 7,077 acres of suitable desert tortoise habitat in the Project Disturbance Area. It should be noted that this total includes impacts associated with the substation. Impacts associated with the substation were included in the impacts and compensation tables reported in the Habitat Mitigation and Monitoring Plan (AECOM 2010) submitted as part of the Data Responses, dated January 4, 2010. Subsequently, PVSI submitted a letter to the CEC and CDFG on February 12, 2010 reporting revised impact numbers for state jurisdictional waters and sensitive species to reflect removal of the substation impacts. The impacts associated with the substation and the compensatory mitigation are the responsibility of Southern California Edison (SCE), the future developer and operator of the substation. The first table reflects the removal of the substation impacts and resulting compensation from these calculations. The applicant provides Bio 1 A to denote impacts caused by the CRSS expansion for which SCE is responsible. Please note that PVSI's biological consultant is currently conducting spring surveys for the transmission line corridor, Colorado River substation, and additional Project Disturbance Areas not previously identified in prior surveys to date. Therefore, impacts to desert tortoise will be revised again and reported to the CEC in separate reports to be forthcoming later this spring.

Table BIO-1. Impacts to Mojave Desert Tortoise Habitat

Species	Low Quality Habitat[1] (acres)	Moderate Quality Habitat[2] (acres)	Total Impact (acres)
Desert Tortoise	3,310.1	3,733.3	7,043.4

1 *Low Quality Habitat* – Limited availability of easily accessible washes that have sufficient cover and forage for desert tortoises or alternatively the habitat has sufficient vegetation disturbance that reduces the quality of the cover and forage for desert tortoise. Low quality habitat is typically unoccupied or has very rare observations of desert tortoises and has limited or no sign indicating use by desert tortoise.

2 *Moderate Quality Habitat* – Contains annual vegetation or shrub cover within the area sufficient to support forage and cover needs, but the habitat quality will include areas with high amounts of cover/forage interspersed with areas with low amounts of cover/forage (i.e. desert washes with upland desert pavement). Moderate quality may also be considered more "upland" for the desert and have lower amounts of cover/forage but are within an area where desert tortoises can readily access washes. Moderate quality habitat is typically occupied by desert tortoises, but at densities that are considered sparse and has desert tortoise sign present. Alternatively, high quality habitat would be considered habitat with annual vegetation and shrub cover sufficient to support forage and cover requirements for desert tortoise (shrubs for burrows, annual vegetation within the spring sufficient to meet nutritional requirements for desert tortoises and is typically within or directly adjacent to a desert wash. High quality habitat is typically occupied by desert tortoises and has substantive sign indicating use of the habitat.

Table BIO-1a. Impacts to Mojave Desert Tortoise Habitat within CRSS

Species	Low Quality Habitat[1] (acres)	Moderate Quality Habitat[2] (acres)	Total Impact (acres)
Desert Tortoise	TBD	TBD	TBD

Page C.2-54, Table 6

PVSI does not agree with the mitigation ratios in Table 6. Staff states that CDFG considers vegetated swales as jurisdictional waters of the states that require mitigation at a 1.5:1 ratio. This is contrary to the prior discussions PVSI and its consultants have held with CDFG regarding vegetated swales. During a November site visit with CEC and CDFG, the CEC requested that creosote bush-big galleta grass association be considered a special vegetation community (not waters of the State). CDFG then requested that the PVSI map all vegetated swales and that they would consider them jurisdictional, but not consider them significant aquatic features that would require mitigation. PVSI provided the mapping in order to be cooperative but has not conceded that such swales are jurisdictional nor should require mitigation.

Page C.2-50 to 54, Table 5 Summary of Impacts and Mitigation, and Table 6 Direct and Indirect Impacts to Waters of the State and Recommended Mitigation

Some of the impacts to biological resources reported in Tables 5 and 6 are inaccurate based on data collected in surveys conducted by PVSI's biological consultant, or they are inconsistent with other numbers stated elsewhere in the SA/DEIS. Tables BIO-2 and BIO-3 provide a comparison of the impact numbers reported in the SA/DEIS and the impact numbers reported in the Data Request Responses prepared by the PVSI. As shown in the tables, the impacts reported in the SA/DEIS are higher for desert tortoise (33.6 acres), Mojave fringe-toad lizard (0.3 acres), and desert dry wash woodland (0.2 acres). Please note that PVSI's biological consultant is currently conducting spring surveys for the transmission line corridor, Colorado River substation, and additional Project Disturbance Areas not previously identified in prior surveys to date. Therefore, impacts to biological resources will be revised again and reported to the CEC in separate reports forthcoming.

Table BIO-2. Summary of Impacts and Mitigation as Stated in the SA/DEIS

Resource		Impact Acreage or Linear Feet			Mitigation Requirement	
		Total Impact	Impact by Quality		Ratio	Acreage
Desert Tortoise (DT)	*Outside habitat conservation areas*	7077	M	Not specified	-	-
			L	Not specified	-	-
	Total:	**7077[1]**			**1:1**	**7077**
Mohave Fringe Toed Lizard (MFTL)		4.0			3:1	12.0
Western burrowing owl (WBO)		2 individual			19.5 ac each[2]	39
Creosote bush scrub-big galleta grass community		406.0			NA	NA
Jurisdictional Waters - Direct	Desert dry wash woodland	175.4			3:1	526.2
	Unvegetated ephemeral dry Wash	7.5			1:1	7.5
	Swale supporting wash-dependent vegetation	367.4			1.5:1	551.1
	Total:	**550.3[3]**			**NA**	**1084.8**
Jurisdictional Waters	Desert dry wash woodland	94.5			1.5:1	141.8
	Unvegetated ephemeral dry Wash	0.8			0.5:0	0.8
	Swale supporting wash-dependent vegetation	38.5			0.75:1	57.8
	Total:	**133.8**			**NA**	**200.3**
Total:		**NA[4]**			**NA[4]**	

Notes:

[NA] Not Applicable

[M] Moderate Quality Habitat (habitat that would necessitate higher mitigation ratios within the category)

[L] Lower Quality Habitat (habitat that would justify lower mitigation ratios within the category)

[1] The SA/DEIS inconsistently reports impacts to desert tortoise habitat. Page C.2-28 states that there are 7,077 acres of suitable habitat within the Project Disturbance Area while page C.2-51 states that the Project will result in 7,040 acres of permanent loss to desert tortoise habitat.

[2] Acres per pair or individual.

[3] The SA/DEIS inconsistently reports impacts to jurisdictional waters of the State. Page C.2-51 states that the Project will result in 551.1 acres of permanent direct impacts to State waters while Table 6 on page C.2-54 stated tha the Projec twill result in 550.3 acres of permanent direct impacts to State waters.

[4] The total impact/mitigation acreage is not provided because it is not additive. The mitigation acreage/fee would not be additive where multiple species and habitat exist on site, or where conservation areas for species overlap (p. 2-35, WEMO BLM).

Table Bio-3. Summary of Impacts Reported by Applicant in Data Request Responses and Proposed Mitigation

Resource		Impact Acreage or Linear Feet: Total Impact	Impact Acreage or Linear Feet: Impact by Quality		Mitigation Requirement: Ratio	Mitigation Requirement: Acreage
Desert Tortoise (DT)	*Outside habitat conservation areas*	7043.4	M	3733.3	1:1	3733.3
			L	3310.1	0.5:1	1655.1
	Total:	**7043.4**			**NA**	**5388.4**
Mohave Fringe Toed Lizard (MFTL)		3.7			1:1	3.7
Western burrowing owl (WBO)		1 individual			6.5 ac each[1]	6.5
Creosote bush scrub-big galleta grass community		406.0			NA[2]	NA
Jurisdictional Waters[3]	Desert dry wash scrub	269.7			2:1	539.4
	Unvegetated ephemeral dry Wash	8.3			1:1	8.3
	Swale supporting wash-dependent vegetation	405.9			NA[4]	NA
	Total:	**683.9**			**NA**	**547.7**
Total:		**NA[5]**			**NA[6]**	

Notes:

NA Not Applicable

H Higher Quality Habitat (habitat that would necessitate higher mitigation ratios within the category)

L Lower Quality Habitat (habitat that would justify lower mitigation ratios within the category)

1 Acres per pair or individual. This ratio assumes project proponent will find occupied habitat.

2 It is assumed Creosote bush scrub-big galleta grass community could possibly be accomplished in combination with required mitigation for State jurisdictional waters and sensitive wildlife species. This acreage is duplicative with the swale acreage defined under jurisdictional waters.

3 Acreage total includes direct and indirect impacts.

4 It is assumed swales are not jurisdicational and would not require mitigation as jurisdictional state waters.

5 The total impact/mitigation acreage is not provided because it is not additive. The mitigation acreage/fee would not be additive where multiple species and habitat exist on site, or where conservation areas for species overlap (p. 2-35, WEMO BLM).

6 Mitigation may be achieved by a combination of land acquisition and a fee program (payment of a acreage based fee) to be determined in coordination with the agencies.

Page C.2-78, Last Paragraph, Decommissioning and Reclamation Plan

Staff states in this paragraph that the Decommissioning and Reclamation Plan must "explicitly state that the goals of reclamation include restoration of the site's topography and hydrology to a relatively natural condition and restoration of native plant communities." However, this may not be the case. BLM, as the ultimate manager of the land, may elect in the future that it may want the site decommissioned or reclaimed to a different land use (continued utility-scale energy generation, OHV, other industrial use, use of some of the buildings, etc.) as opposed to restoration. Since the project has provided full habitat compensation to mitigate for all project disturbance and that habitat compensation mitigates for the life of the project and beyond, there is no environmental reason to restore the land to a natural state unless BLM, as the land manager requests restoration.

Under the provisions of the BLM ROW lease, PVSI expects to be required to provide the BLM a conceptual reclamation plan prior to start of construction and a detailed reclamation plan years later as the BSPP approaches the end of its operational life. PVSI requests that the objectives and detailed content of the reclamation plan for the BSPP site be determined at that future time when are development and the BLM's long-term interests and objectives are better defined than they can be at present. A condition to this effect is requested.

Page C.2-93, Table 10

All aquatic features; including desert Dry Wash Woodland, Unvegetated Ephemeral Dry Wash, and vegetated swale features (populated by the Creosote Bush -Big Galleta Grass Association [and to a much lesser extent desert lavender and desert star vine]) occurring within the BSPP area have been formally delineated, discretely mapped, and field verified by qualified ecologists within the boundary of the BSPP utilizing and applying the most up to date Federal and State delineation guidance (including on-site agency guidance by the CDFG) and methodology. The National Hydrography Dataset and California Interagency Watershed Map are *general reference* maps, and are based at the watershed level (primarily utilizing topographic features) to ascertain the presence, location, extent and amount of riverine and/or riverine-like features. Therefore, the amount (in linear feet and area) of aquatic features occurring within the BSPP is accurate based upon field studies. No field studies (e.g., delineations) of aquatic features were conducted outside the BSPP project boundary except along linear corridors for Project-related roads and transmission lines.

Page C.2-94, Cumulative Impacts, First Paragraph

Assessments of habitat quality can be conducted using both a model and field evaluations; however, a model should not be applied or used in a vacuum. Any model has limitations and should be verified and refined based on field observations. The USGS Model was applied to the site and did identify the site as having low quality lands, which is consistent with our field findings. As stated in the SA/DEIS the model should not be used, or viewed, as "a substitute for ground-based and site-specific field surveys" therefore, it is important to make decisions based on specific field conditions as observed during surveys. The surveys of the site identify site disturbances and conditions that result in low quality habitat that is unoccupied by desert tortoise. It is believed that mitigation for both direct and cumulative impact to desert tortoise for this project can be mitigated to a less than significant level with the implementation of compensatory mitigation at a ratio agreed to with the resource agencies.

Page C.2-95, Cumulative Impacts, First Paragraph

The current "undetermined" conclusion regarding potential cumulative impacts to desert tortoise habitat connectivity in the BSPP SA/DEIS should be changed to a conclusion of no impact. The rationale for this altered conclusion is low desert tortoise habitat quality of half of the BSPP site (approximately 3,310 acres) and its geographic position in relation to the Desert Wildlife Management Areas (DWMAs) and areas of desert tortoise critical habitat in other portions of the desert. There is evidence of a low-density tortoise population to the west of the BSPP. One desert tortoise was found in the extreme southwest corner of the proposed BSPP site. Two additional tortoises were found in the western buffer. The Chuckwalla DWMA and the associated desert tortoise Critical Habitat is approximately 8 miles to the west of the main disturbance area of the proposed BSPP and 2 miles southwest of the proposed substation to be constructed by Southern California Edison. The proposed project will not interfere with connectivity between these areas and the tortoise population to the west of the BSPP site. The next closest DWMAs or areas of desert tortoise Critical Habitat are more than 30 miles distant to the north and northwest. Desert tortoise connectivity between these areas is clearly not being maintained via the BSPP site at present. In addition, the geographic position of the BSPP site, along with its habitat characteristics, suggests that establishment of habitat connectivity via recolonization of new home ranges by desert tortoise would occur by other routes to the west of the site.

Page C.2-116, Verification to Condition of Certification BIO-1

The second paragraph of the Verification to Condition BIO-1 requires submittal of the approved Designated Biologist within 7 days of receiving the Energy Commission Decision. PVSI requests this be modified consistent with other conditions that measure the verification timeline "prior to" an activity such as mobilization or construction. In addition, language has been added to the verification for clarification. PVSI requests the Verification be modified as follows.

> The Project owner shall submit **to** the CPM and Authorized Officer **the** approved Designated Biologist ***no less than 30 days prior to construction*** ~~within 7 days of receiving the Energy Commission Decision.~~ No construction-related ground disturbance, grading, boring, or trenching shall commence until an approved Designated Biologist is available to be on site.

Page C.2-120, Verification to Condition of Certification BIO-6

The first paragraph of the Verification to Condition of Certification BIO-6 requires submittal of the final WEAP within 7 days of receiving the Energy Commission Decision or Record of Decision. PVSI requests this be modified consistent with other conditions that measure the verification timeline "prior to" an activity such as mobilization or construction. The Verification should be modified as follows.

> Verification: ~~Within 7 days of publication of the Energy Commission's License Decision, or Record of Decision/ROW Issuance, whichever comes first,~~ ***No less than 30 days prior to construction*****,** the Project owner shall provide to BLM's Authorized Officer and the CPM a copy of the final WEAP and all supporting written materials and electronic media

prepared or reviewed by the Designated Biologist and a resume of the person(s) administering the program. No construction-related ground disturbance, grading, boring, or trenching shall commence until an approved Designated Biologist is available to be on site.

Page C.2-122, Verification to Condition of Certification BIO-7

The third paragraph of the Verification to this Condition of Certification requires verification that the extent of construction disturbance does not exceed that described in the SA/DEIS by submitting aerial photographs before and after completion. Aerials can be used to verify boundaries, but they are difficult to use for acreage calculations to 10th's of an acre. PVSI suggests using whole acreage numbers in making this comparison. Revisions to the disturbance area calculations are currently in progress based on updates to the alignment of linear project features. Updated habitat impact and disturbance area calculations will be provided to the CEC subsequent to completion of biological resource surveys currently being conducted this spring for the transmission line corridor, Colorado River substation, and additional Project Disturbance Areas not previously identified in prior surveys to date. Therefore, impacts to biological resources will be revised again and reported to the CEC in separate reports forthcoming later this spring. Because the Project Disturbance Area may be revised from that described in the SA/DEIS, PVSI requests that the third paragraph of this verification be modified as follows.

> To verify that the extent of construction disturbance does not exceed that described in ~~this analysis~~ ***these Biological Resources Conditions of Certification***, the Project owner shall submit aerial photographs, at an approved scale, taken before and after construction to the CPM and BLM's Authorized Officer.

Pages C.2-121 to 126, Condition of Certification BIO-8

The second paragraph of the Verification to this Condition of Certification requires submittal of a Revegetation Plan no less than 30 days after the CEC issues the License or BLM issues the ROW. PVSI requests this be modified consistent with other conditions that measure the verification timeline "prior to" an activity such as mobilization or construction. We request the Verification be modified as follows.

> No less than 30 days ***prior to construction*** ~~following the publication of the Energy Commission License Decision or the Record of Decision/ROW Issuance, whichever comes first,~~ the project owner shall submit to the CPM and BLM's Authorized Officer a final agency-approved Revegetation Plan that has been reviewed and approved by BLM's Authorized Officer and the CPM. All modifications to the Revegetation Plan shall be made only after approval from BLM's Authorized Officer and the CPM.

Pages C.2-127-129, Condition of Certification BIO-9

The USFWS' 2009 *Desert Tortoise Field Manual* (Chapter 6 – Clearance Survey Protocol for the Desert Tortoise – Mojave Population) stipulates protocol for clearance surveys for "*occupied* desert tortoise habitat" (emphasis added). It is important to note that only one (1) adult desert tortoise was observed in the southwest corner of the BSPP disturbance area. As previously stated, the lack of desert tortoise sign in the eastern side of the Biological Resources Survey Area (other than disarticulated and scattered bone fragments that likely have washed down from carcasses on the western side of the BRSA) suggest that desert tortoises do not occupy the eastern side of the BRSA. Therefore, it should be feasible to conduct clearance surveys for unoccupied desert tortoise habitat throughout the year. PVSI requests that the language of Condition BIO-9 be revised according to the suggested edits below.

This condition requires tortoise exclusion fencing to be included in the permanent security fencing for the plant site and allows temporary tortoise exclusion fencing for linear features. In order to facilitate construction and meeting the ARRA funding start of construction deadline, it would be helpful to be allowed to install temporary exclusion fencing around some portion of the plant site so that clearance surveys and construction could begin within a subset of the site. Therefore PVSI recommends the following modification to the proposed condition.

1. Desert Tortoise Exclusion Fence Installation. To avoid impacts to desert tortoises, permanent desert tortoise exclusion fencing shall be installed along the permanent perimeter security fence and temporarily installed along the ~~utility corridors~~ ***linear features or around any subset of the plant site where construction would be localized***. The proposed alignments for the permanent perimeter fence and ***alignments of temporary fencing along linear features or any subset of the plant site where construction would be localized*** ~~utility rights-of-way~~ ~~fencing~~ shall be flagged and surveyed within 24 hours prior to the initiation of fence construction. Clearance surveys of the perimeter fence ***alignment and the alignment of any temporary fencing along linear features or around any subset of the plant site where construction would be localized*** ~~and utility rights-of-way alignments~~ shall be conducted by the Designated Biologist(s) using techniques outlined in the USFWS' 2009 *Desert Tortoise Field Manual*. And may be conducted in any season with USFWS and CDFG approval. Biological Monitors may assist the Designated Biologist under his or her supervision. These fence clearance surveys shall provide 100% coverage of all areas to be disturbed and an additional transect along both sides of the fence line. This fence line transect shall cover an area approximately 90 feet wide centered on the fence alignment. Transects shall be no greater than 15 feet apart. All desert tortoise burrows, and burrows constructed by other species that might be used by desert tortoises, shall be examined to assess occupancy of each burrow by desert tortoises and handled in accordance with the USFWS' 2009 *Desert Tortoise Field Manual*. Any desert tortoise located during fence clearance surveys shall be handled by the Designated Biologist(s) in accordance with the USFWS' 2009 *Desert Tortoise Field Manual*.

   a. Timing, Supervision of Fence Installation. The exclusion fencing shall be installed ***in an area*** prior to the onset of site clearing and grubbing ***in that area***. The fence installation shall be supervised by the Designated Biologist and monitored by the Biological Monitors to ensure the safety of any tortoise present.

~~c. Security Gates. Security gates shall be designed with minimal ground clearance to deter ingress by tortoises. The gates may be electronically activated to open and close immediately after the vehicle(s) have entered or exited to prevent the gates from being kept open for long periods of time. Cattle grating designed to safely exclude desert tortoise shall be installed at the gated entries to discourage tortoises from gaining entry.~~

2. Desert Tortoise Clearance Surveys within the Plant Site. Following construction of the permanent perimeter security fence and the attached tortoise exclusion fence, the permanently fenced power plant site shall be cleared of tortoises by the Designated Biologist, who may be assisted by the Biological Monitors. ***Portions of the power plant site may be fenced with temporary tortoise exclusion fence to facilitate construction of the power plant site in stages and in such cases the area within the temporary tortoise exclusion fence shall be cleared of tortoises.*** Clearance surveys shall be conducted in accordance with the USFWS' 2009 *Desert Tortoise Field Manual* (Chapter 6 – Clearance Survey Protocol for the Desert Tortoise – Mojave Population) and shall consist of two surveys covering 100% the project area by walking transects no more than 15-feet apart. If a desert tortoise is located on the second survey, a third survey shall be conducted. Each separate survey shall be walked in a different direction to allow opposing angles of observation. ***Clearance surveys of the power plant site that contain unoccupied desert tortoise habitat (i.e. the eastern portion and the northwestern corner of the power plant site where power block units #1, 2 and 4 would be located) may be conducted throughout the year.*** Clearance surveys of the power plant site ***that contain occupied desert tortoise habitat (i.e. the southwest corner of the power plant site where power block unit #3 would be located)*** may only be conducted when tortoises are most active (April through May or September through October). Surveys outside of these time periods ***in occupied desert tortoise habitat*** require approval ***(via e-mail or authorization letter)*** by USFWS and CDFG. Any tortoise located during clearance surveys of the power plant site shall be relocated and monitored in accordance with the Desert Tortoise Relocation/Translocation Plan

Page C.2-130, Verification to Condition of Certification BIO-10

The Verification to this Condition of Certification requires submittal of a Desert Tortoise Relocation/Translocation Plan no less than 30 days after the CEC issues the License or BLM issues the ROW. PVSI requests this be modified consistent with other conditions that measure the verification timeline "prior to" an activity such as mobilization or construction. We request the Verification be modified as follows:

Verification: ~~Within 7 days of docketing of the Energy Commission License Final Decision or publication of BLM's Record of Decision/ROW Issuance, whichever comes first,~~ ***Thirty days (30) prior to site***

mobilization, the Project owner shall provide BLM's Authorized Officer and the CPM with the final version of a Desert Tortoise Relocation/Translocation Plan that has been reviewed and approved by BLM's Authorized Office and the CPM in consultation with USFWS and CDFG. All modifications to the approved Plan shall be made only after approval by BLM's Authorized Officer and the CPM, in consultation with USFWS and CDFG.

Page C.2-130, Condition of Certification BIO-11

This condition of certification includes a contractual "hold harmless" clause which should not be imposed on an applicant as a regulatory mandate and therefore should be removed from a Condition of Certification.

Pages C.2-132-136, Condition of Certification BIO-12

Condition of Certification BIO-12 provides the framework and criteria for habitat compensation and land acquisition. PVSI believes that funding of programs in lieu of strict land acquisition could provide a great benefit to the Desert Tortoise conservation and discussed such an approach in its mitigation proposals in response to Staff data requests. We understand that CDFG is considering implementing a "in lieu fee" program and advanced mitigation strategies intended for renewable energy projects seeking ARRA funding pursuant to new authorizing legislation. While this fee is voluntary and the amount is unknown at this time, PVSI requests that the Staff revise this condition to allow flexibility in mitigation strategies beyond mere land acquisition. PVSI would like to explore alternative mitigation strategies such as those outlined in our mitigation proposal in the upcoming SA/DEIS Workshop.

The discussion in paragraph 2 on Page C.2-58 of the SA/DEIS states: "staff has concluded mitigation at a 1:1 ratio through land acquisitions ***or an assessed financial contribution*** based on the final construction footprint would mitigate for this significant habitat loss [7,040 acres]." The SA/DEIS cites the Northern and Eastern Colorado Desert Coordinated Management Plan (NECO) as the guidance used to determine adequate compensatory mitigation for impacts to desert tortoise habitat.

According to the NECO, compensation for impacts to lands within the plan area may be achieved through lands or equivalent fees. Specific requirements are outlined in Section 4 of Appendix D of the Plan, Desert Tortoise Mitigation Measures, which are also cited on Page C.2-58 of the SA/DEIS: "A mitigation fee based on the amount of acreage disturbed shall be required of proponents of new development. Within DWMAs (Category I) the lands delivered or equivalent fee shall be an amount that achieves a ratio of 5 acres of compensation land for every 1 acre disturbed. Outside DWMAs (Category III) the lands delivered or equivalent fee shall be an amount that achieves a ratio of one (1) acre of compensation land for every one (1) acre disturbed. Funds may be expended as approved by the Management Oversight Group in 1991. Lands will be acquired or enhanced within the same recovery unit as the disturbance. CDFG may require additional fees for management of lands and for rehabilitation of lands." These ratios are not necessarily inflexible based on further evaluation of the NECO plan. In the Constraints and Development section of Appendix B (Standards and Guidelines) of the Plan, it states: "In applying the standards and any applicable guidelines, BLM will emphasize a balanced approach to resource management, taking into account such factors as context and intensity of impacts; the opportunities for reclamation, restoration, or rehabilitation; and possible mitigation, including off-site mitigation." The context of impacts presumably includes quality of habitat impacted, allowing BLM the flexibility to negotiate mitigation ratios particularly if higher value mitigation lands are proposed.

A fee equivalent compensation option is clearly supported by the NECO plan and it seemed to be the intention of Staff to include that flexibility in this compensation condition (BIO-12) based on the statement identified above on Page C.2-58. Those funds can be used in furtherance of any of the current or developing efforts summarized in The Summary of Desert Tortoise Recovery Actions Northern Colorado Recovery Unit. These actions include securing habitat within Desert Wildlife Management Areas (DWMAs), rehabilitation or closure of roads within DWMAs, removal of wild horses and burros, cleanup of illegal dumps, fencing of roads, providing movement corridors under roads, and desert revegetation projects. Therefore, it is reasonable that based on these provisions of the NECO, compensation should be a combination of lands and equivalent fees, the ratio of compensation lands outside DWMAs can be negotiated as a function of the context of the impacts and mitigation lands, and the fee-based compensation can be used to fund restoration and enhancement efforts conducted as a part of Desert Tortoise Recovery Actions under way in the Northern Colorado Recovery Unit.

PVSI also requests that this condition be revised to allow the mitigation to more closely match the timing of construction. We have revised the condition for Staff's consideration in a manner to allow funding and acquisition to be independently tied to timing of construction of each power plant unit.

BIO-12 To fully mitigate for habitat loss and potential take of desert tortoise, the Project owner shall provide compensatory mitigation ~~at a 1:1 ratio~~ ***in accordance with Table 1***, ***which may include compensation lands purchased in fee or in easement, equivalent fees, or a combination thereof,*** for impacts to 7,040 acres or the area disturbed by the final Project footprint. ***The timing of the mitigation shall correspond with the timing of the site disturbance activities using the following method.***

1. ***Thirty days prior to the commencement of initial construction activities, the project owner shall provide to the CPM for approval an estimate of the amount of disturbance associated with the construction activities for the initial 12 months.***
2. ***Thirty days prior to commencement of the next 12 months, of construction activities, following the initial or preceding 12 months of construction activities, the project owner shall provide to the CPM for approval an estimate of the amount of disturbance associated with the construction activities for the next 12 months of construction activities.***
3. ***Within 18 months after construction activities commence the project owner shall provide the mitigation commensurate with each 12-month disturbance estimate.***

If compensation lands are acquired in fee or in easement, ~~T~~***the*** requirements for acquisition ~~of 7,040 acres~~ of compensation lands shall include the following:

1. Selection Criteria for Compensation Lands. The compensation lands selected for acquisition ***in fee or in easement*** shall:

   a. be within the Colorado Desert Recovery Unit, with potential to contribute to desert tortoise habitat connectivity and build linkages between desert tortoise designated critical habitat, known populations of desert tortoise, and/or other preserve lands;
   b. provide habitat for desert tortoise with capacity to regenerate naturally when disturbances are removed;
   c. ***to the extent practicable*** be ***prioritized*** near larger blocks of lands that are either already protected or planned for protection, or which could feasibly be protected long-term by a public resource agency or a non-governmental organization dedicated to habitat preservation;
   d. ***to the extent practicable*** be connected to lands currently occupied by desert tortoise, ideally with populations that are stable, recovering, or likely to recover;
   e. not have a history of intensive recreational use or other disturbance ***that is of an extent*** that ***does not have the capacity to regenerate naturally when disturbances are removed or*** might make habitat recovery and restoration infeasible;not be characterized by high densities of invasive species, either on ***or immediately adjace***nt to ***the parcels under consideration, that might jeopardize habitat recovery and restor***ation; and
   a. not contain hazardous wastes ***that cannot be removed to the extent that the site is suitable for habitat.***

2. Review and Approval of Compensation Lands***/Equivalent Fee Program*** Prior to Acquisition. A minimum of three months prior to acquisition ***(through purchase or easement)*** of the property ***or implementing/participating in the equivalent fee program***, the Project owner shall submit a formal ~~acquisition~~ proposal to the CPM, CDFG, USFWS and BLM describing the parcel(s) intended for purchase ***and/or the recovery or lieu fee or species recovery programs to be funded***[2]. This ~~acquisition~~ proposal shall

[2] The mitigation programs include potential BLM lands as defined by the REAT Agencies. REAT Agencies have proposed mechanisms such as deed restrictions, conservation easements, or right-of-way exclusion areas that would provide permanent protection for acquired mitigation lands under BLM management.

discuss the suitability of the proposed parcel(s) as compensation lands for desert tortoise in relation to the criteria listed above ***and/or the contribution of the program or fund to the recovery of the species as well as documentation of the proposed compensation equivalency***. Approval from CDFG and the CPM, in consultation with BLM and the USFWS, shall be required for acquisition of all parcels comprising the ~~7,040~~ ***the amount of mitigation provided in Table 1*** ~~acres~~.

a. Mitigation Security: The Project owner shall provide financial assurances to the CPM and CDFG with copies of the document(s) to BLM and the USFWS, to guarantee that an adequate level of funding is available to implement the mitigation measures described in this condition, ***including assurances for 12 month increments as described above.*** These funds shall be used solely for implementation of the measures associated with the Project. Financial assurance can be provided to the CPM and CDFG in the form of an irrevocable letter of credit, a pledged savings account or another form of security (—Security||) prior to initiating ground-disturbing Project activities. Prior to submittal to the CPM, the Security shall be approved by the CPM and BLM's Authorized Officer, in consultation with CDFG and the USFWS, to ensure funding. ~~As of the publication of the SA/DEIS, this amount is $16,050,516. The Security requirement would be $12,430,560 if the Reconfigured Alternative were constructed or $9,525,840 for the Reduced Acreage Alternative. This Security amount was calculated as follows and may be revised based on land costs or the estimated costs of enhancement and endowment (see subsection C.2.4.2, Desert Tortoise, for a discussion of the assumptions used in calculating the Security, which are based on an estimate of $2,280 per acre to fund acquisition, enhancement, and long-term management).~~ The final amount due will be determined by the PAR analysis conducted pursuant to this condition.

3. Compensation Lands Acquisition Conditions: The Project owner shall comply with the following conditions relating to acquisition of the compensation lands after the CPM and BLM's Authorized Officer, in consultation with CDFG and the USFWS, have approved the proposed compensation lands and received Security as applicable and as described above.

a. Preliminary Report: The Project owner, or approved third party, shall provide a recent preliminary title report, initial hazardous materials survey report, biological analysis, and other necessary documents for the proposed ~~7,040~~ acres. All documents conveying or conserving compensation lands and all conditions of title/easement are subject to a field review and approval by the CPM and BLM's Authorized Officer, in consultation with CDFG and the USFWS, California Department of General Services and, if applicable, the Fish and Game Commission and/or the Wildlife Conservation Board.
b. Title/Conveyance: The Project owner shall transfer fee title or a conservation easement to the ***proposed*** acres of compensation lands to CDFG under terms approved by the CPM and CDFG. Alternatively, a non-profit organization qualified to manage compensation lands (pursuant to California Government Code section 65965) and approved by CDFG and the CPM may hold fee title or a conservation easement over the habitat mitigation lands. If the approved non-profit organization holds title, a conservation easement shall be recorded in favor of CDFG in a form approved by CDFG. If the approved non-profit holds a conservation easement, CDFG shall be named a third party beneficiary. If a Security is provided, the Project owner or an approved third party shall complete the proposed compensation lands acquisition within 18 months of the start of Project ground-disturbing activities.
c. Initial Habitat Improvement Fund. The Project owner shall fund the initial protection and habitat improvement of the ***compensation land*** ~~7,040 acres~~. Alternatively, a non-profit organization may hold the habitat improvement funds if they are qualified to manage the compensation lands (pursuant to California Government Code section 65965) and if they meet the approval of CDFG and the CPM. If CDFG takes fee title to the compensation lands, the habitat improvement fund must go to CDFG.
d. Conduct a Property Analysis Record. Upon identification of the mitigation lands the property owner shall conduct a Property Analysis Record (PAR) or PAR-like analysis to establish the appropriate endowment to fund the in-perpetuity management of the acquired mitigation lands.
e. Long-term Management Endowment Fund. ***Within 18 months of*** ~~Prior to~~ ground-disturbing Project activities, the Project owner shall provide to CDFG a non-wasting capital endowment in the amount determined through the Property Analysis Record (PAR) or PAR-like analysis that would be conducted

for the ***compensation land***. ~~7,040 acres~~. Alternatively, a non-profit organization may hold the endowment fees if they are qualified to manage the compensation lands (pursuant to California Government Code section 65965) and if they meet the approval of CDFG and the CPM. If CDFG takes fee title to the compensation lands, the endowment must go to CDFG, where it would be held in the special deposit fund established ***solely for the purpose to manage lands in perpetuity*** ~~pursuant to California Government Code section 16370~~. If the special deposit fund is not used to manage the endowment, the California Wildlife Foundation or similarly approved entity identified by CDFG shall manage the endowment for CDFG and with CDFG supervision.

f. Interest, Principal, and Pooling of Funds. The Project owner, CDFG and the CPM shall ensure that an agreement is in place with the endowment holder/manager to ensure the following conditions:

   i. Interest. Interest generated from the initial capital endowment shall be available for reinvestment into the principal and for the long-term operation, management, and protection of the approved compensation lands, including reasonable administrative overhead, biological monitoring, improvements to carrying capacity, law enforcement measures, and any other action approved by CDFG designed to protect or improve the habitat values of the compensation lands.

   ii. Withdrawal of Principal. The endowment principal shall not be drawn upon unless such withdrawal is deemed necessary by the CDFG or the approved third-party endowment manager to ensure the continued viability of the species on the ***compensation lands*** ~~7,040 acres~~. If CDFG takes fee title to the compensation lands, monies received by CDFG pursuant to this provision shall be deposited in a special deposit fund established ***solely for the purpose to manage lands in perpetuity***~~pursuant to Government Code section 16370~~. If the special deposit fund is not used to manage the endowment, the California Wildlife Foundation or similarly approved entity identified by CDFG would manage the endowment for CDFG with CDFG supervision.

   iii. Pooling Endowment Funds. CDFG, or a CPM and CDFG approved non-profit organization qualified to hold endowments pursuant to California Government Code section 65965, may pool the endowment with other endowments for the operation, management, and protection of the

~~7,040 acres~~ ***compensation lands*** for local populations of desert tortoise. However, for reporting purposes, the endowment fund must be tracked and reported individually to the CDFG and CPM.

iv. Reimbursement Fund. The Project owner shall provide reimbursement to CDFG or an approved third party for reasonable expenses incurred during title, easement, and documentation review; expenses incurred from other state or state approved federal agency reviews; and overhead related to providing compensation lands. The Project owner is responsible for all compensation lands acquisition/easement costs, including but not limited to, title and document review costs, as well as expenses incurred from other state agency reviews and overhead related to providing compensation lands to the department or approved third party; escrow fees or costs; environmental contaminants clearance; and other site cleanup measures.

Verification: No later than 30 days prior to beginning ~~Project ground-disturbing activities~~ *construction*,, the Project owner shall provide written verification of security in accordance with this condition of certification. The Project owner, or an approved third party, shall complete and provide written verification of the proposed compensation lands acquisition ***and/or funding of the in liue fee or specific recovery programs*** within 18 months of the start of Project ground-disturbing activities.

No less than ~~90~~ ***30*** days prior to acquisition of the property ***and/or funding of the in liue fee or specific recovery programs***, the Project owner shall submit a formal ~~acquisition~~ proposal to BLM's Authorized Officer, the CPM, CDFG, and USFWS describing the parcels intended for ~~purchase~~ ***acquisition through purchase or easement and/or the in liue fee or specific recovery programs to be funded***. The Project owner, or an approved third party, shall provide BLM's Authorized Officer, the CPM, CDFG, and USFWS with a management plan for the compensation lands and associated funds ***and/or equivalent fee program*** within180 days of the land or easement purchase ***or funding of the program***, as determined by the date on the title. BLM's Authorized Officer and the CPM shall review and approve the management plan, in consultation with CDFG and the USFWS.

Within 90 days after completion of Project construction, the Project owner shall provide to the CPM and CDFG an analysis with the final accounting of the amount of habitat disturbed during Project construction.

If compensation lands are acquired, t~~T~~he Project owner shall provide written verification to BLM's Authorized Officer, the CPM, USFWS and CDFG that the compensation lands or conservation easements have been acquired and recorded in favor of the approved recipient no later than 18 months ***from the start of ground-disturbing activities*** ~~from adoption of the Final Energy Commission decision~~ for the Blythe Solar ***Power P***~~Energy p~~roject.

Pages C.2-136 and 137, Condition of Certification BIO-13

PVSI request this condition be deleted for the reasons articulated below in our comments to Condition of Certification BIO-21.

Page C.2-137-138, Condition of Certification BIO-15

The Verification to this Condition of Certification requires submittal of an Avian Protection Plan no less than 10 days after the CEC issues the License or BLM issues the ROW. PVSI requests this be modified consistent with other conditions that measure the verification timeline "prior to" an activity that gives rise to the impacts. In the case of potential impacts to birds a more appropriate timeline would be prior to commercial operation. We request the Verification be modified as follows

> **<u>Verification:</u>** No less than ~~10~~ ***30*** days ~~following the docketing of the Energy Commission License Decision or publication of BLM's Record of Decision/ROW Issuance, whichever comes first,~~ ***prior to commercial operation of any of the power plant units*** the project owner shall submit to the CPM, BLM's Authorized Officer, USFWS and CDFG a final Avian Protection Plan. Modifications to the Avian Protection Plan shall be made only after approval from BLM's Authorized Officer and the CPM.

Page C.2-138-139, Condition of Certification BIO-16

This condition requires nest surveys. To facilitate staged construction, PVSI requests the following modifications so that nest surveys can be concentrated to only those portions of the project site that may be undergoing construction.

> **BIO-16** Pre-construction nest surveys shall be conducted if construction activities would occur from February 1 through August 31. The Designated Biologist or Biological Monitor conducting the surveys shall be experienced bird surveyors familiar with standard nest-locating techniques and shall perform surveys in accordance with the following guidelines:
>
> 1. Surveys shall cover all potential nesting habitat in the ***portion of the area to be constructed*** ~~Project site~~ or within 500 feet of the boundaries of the ***portion of the are to be constructed*** ~~site~~ (including linear facilities);

Page C.2-140-142, Condition of Certification BIO-18

This condition requires preconstruction burrowing owl surveys. To facilitate staged construction, PVSI requests the following modifications so that the surveys can be concentrated to only those portions of the project site that may be undergoing construction. The Verification to this Condition of Certification requires submittal of a Burrowing Owl Mitigation Plan no less than 10 days after the CEC issues the License or BLM issues the ROW. PVSI requests this be modified consistent with other conditions that measure the verification timeline "prior to" an activity that gives rise to the potential impacts. In the case of potential impacts to burrowing owls the appropriate timeline would be construction. Additionally, PVSI requests this be modified to allow participation in an in lieu fee program for mitigation of burrowing owls.

Additionally, PVSI recommends this condition be modified to reflect that only one pair of WBO are within the project disturbance area. We therefore we request the following modifications:

BIO-18 The Project owner shall implement the following measures to avoid, minimize and offset impacts to burrowing owls:

1. Pre-Construction Surveys. The Designated Biologist or Biological Monitor shall conduct pre-construction surveys for burrowing owls in accordance with CDFG guidelines (California Burrowing Owl Consortium 1993). The survey area shall include the Project Disturbance Area and surrounding 500 foot survey buffer. ***If the project is constructed in stages then the pre-construction surveys should be conducted for the disturbance area and a 500 foot buffer for each stage of construction.***

4. Acquire ~~39~~ ***19.5*** Acres of Burrowing Owl Habitat. The Project owner shall acquire, in fee or in easement ~~39~~ ***19.5*** acres of land suitable to support a resident population of burrowing owls and shall provide funding for the enhancement and long-term management of these compensation lands. The responsibilities for acquisition and management of the compensation lands may be delegated by written agreement to CDFG or to a third party, such as a non-governmental organization dedicated to habitat conservation, subject to approval by the CPM, in consultation with CDFG and USFWS prior to land acquisition or management activities. Additional funds shall be based on the adjusted market value of compensation lands at the time of construction to acquire and manage habitat. ***Alternatively, the Applicant may achieve compensatory mitigation through payment into an approved habitat enhancement fund or other in-lieu fee program.***

Verification: ***At least*** ~~Within~~ 10 days ***prior to start of any Project-related ground disturbance activities*** ~~of docketing of the Energy Commission Final Decision or publication of BLM's Record of Decision/ROW Issuance, whichever comes first,~~ the Project owner shall submit to BLM's Authorized Officer, the CPM, CDFG and USFWS an agency-approved final Burrowing Owl Mitigation Plan.

Revise 4th and 5th paragraphs also as follows: No less than 3 months prior to acquisition of the property, the Project owner, or an approved third party, shall submit a formal ~~acquisition~~ proposal to the CPM, BLM's

Authorized Officer, CDFG, and USFWS describing the ***19.5***~~39~~ acre parcel intended for purchase ***or equivalent fee program to be funded***.

If compensation land is acquired, within 90 days of the land or easement purchase, as determined by the date on the title, the Project owner shall provide the CPM with a management plan for review and approval, in consultation with CDFG, for the compensation lands and associated funds.

Revise 7th paragraph also as follows: No later than 18 months from ***the start of any Project-related ground disturbance activities*** ~~a Energy Commision final Decision or publication of BLM's record of Decision/ROW Issuance, whichever comes first,~~ the project owner shall provide written verification to the BLM's Authorized Officer, the CPM, and CDFG that 39 acres of compensation lands or conservation easements have been acquired and recorded in favor of the approved recipient.

Page C.2-143, Condition of Certification BIO-20

BIO-20 To mitigate for habitat loss and direct impacts to Mojave fringe-toed lizards the project owner shall provide compensatory mitigation at ~~a 3:1~~**1:1** ratio, ***which may include compensation lands purchased in fee or in easement, equivalent fees, or a combination thereof***, for impacts to 4 acres of stabilized or partially stabilized desert dune habitat (or the acreage of sand dune/partially stabilized sand dune habitat impacted by the final project footprint). ***If compensation lands are acquired***, the project owner shall provide funding for the acquisition ***in fee or in easement***, initial habitat improvements and long-term management endowment of the compensation lands.

1. Criteria for Compensation Lands: The compensation lands selected for acquisition shall:

a. Be sand dune or partially stabilized sand dune habitat within the ~~Chuckwalla Valley~~ ***NECO*** with potential to contribute to Mojave fringe-toed lizard habitat connectivity and build linkages between known populations of Mojave fringe-toed lizards and preserve lands with suitable habitat;

b. ***To the extent practicable***, ~~B~~be connected to lands currently occupied by Mojave fringe-toed lizard;

c. ***To the extent practicable***, ~~B~~be near larger blocks of lands that are either already protected or planned for protection, or which could feasibly be protected long-term by a public resource agency or a non-governmental organization dedicated to habitat preservation;

d. Provide quality habitat for Mojave fringe-toed lizard, that has the capacity to regenerate naturally when disturbances are removed;

Verification: No later than 30 days prior to beginning Project ground-disturbing activities, the Project owner shall provide written verification of security in accordance with this condition of certification. The Project owner, or an approved third party, shall complete and provide written verification of the proposed compensation lands acquisition ***and/or funding of the recovery or lieu fee programs*** within 18 months of the start of Project ground-disturbing activities.

No less than 90 days prior to acquisition of the property ***and/or funding of the in lieu fee or species recovery programs***, the Project owner shall submit a formal ~~acquisition~~ proposal to BLM's Authorized Officer, the CPM, CDFG, and USFWS describing the parcels intended for ~~purchase~~ ***acquisition (through purchase or easement) and/or the in lieu fee or species recovery programs to be funded***. The Project owner, or an approved third party, shall provide BLM's Authorized Officer, the CPM, CDFG, and USFWS with a management plan for the compensation lands and associated funds ***and/or equivalent fee program*** within180 days of the land or easement purchase ***or funding of the program***, as determined by the date on the title. BLM's Authorized Officer and the CPM shall review and approve the management plan, in consultation with CDFG and the USFWS.

Within 90 days after completion of Project construction, the Project owner shall provide to the CPM and CDFG an analysis with the final accounting of the amount of habitat disturbed during Project construction.

If compensation lands are acquired, the Project owner shall provide written verification to BLM's Authorized Officer, the CPM, USFWS and CDFG that the compensation lands or conservation easements have been acquired and recorded in favor of the approved recipient no later than 18 months from ~~adoption of the Final Energy Commision Decision~~ ***the start of ground-disturbing activities*** for the ~~Genesis~~ ***Blythe*** Solar ***Power*** ~~Energy~~ ~~p~~***Project***.

Page C.2-145, Condition of Certification BIO-21

The SA/DEIS concludes that big horn sheep are unlikely to use the Project site or the nearby McCoy Mountains. This conclusion was based upon consultation with local experts and agency resource staff. This conclusion is supported by the results of recent Golden Eagle helicopter surveys that detected big horn sheep in other desert mountain ranges further west, but not in the McCoy Mountains. The SA/DEIS includes a mitigation measure requiring establishment of an artificial water source for big horn sheep in the McCoy Mountains as mitigation for "potential future impairment to connectivity" that could occur if the McCoy Mountains someday were host to resident big horn sheep population a result of future translocation or recolonization.

It is a legal requirement that there be a nexus between a mitigation measure and an identified project impact. The proposed BSPP would not adversely affect big horn sheep. A potential future impact to a big horn sheep population that does not currently exist is speculative and not reasonably forseeable. This mitigation measure/Condition of Certification BIO-21 should be deleted.

Page C.2-145, Condition of Certification BIO-22

As discussed above under BIO-12 (desert tortoise compensatory mitigation), the NECO Plan includes the option of directing equivalent funds towards desert dry wash woodland community enhancement or rehabilitation as opposed to simply requiring land acquisition for impacts to this community and other wash habitats. PVSI requests that BIO-22 be modified to allow this flexibility for mitigating impacts to State waters. We also request that the following language be revised to allow greater flexibility given the limited private lands available in the area:

BIO-22 1. … ***To the extent practicable***, ~~M~~mitigation for impacts to state waters ***will be prioritized*** ~~shall~~ within the Palo Verde and surrounding watersheds, as close to the project site as ***practicable*** ~~possible~~.

PVSI requests that Staff reconsider the mitigation ratios in Table 6, p. 54. The SA/DEIS states that CDFG considers vegetated swales to be jurisdictional waters of the State that require mitigation at a 1.5:1 ratio. This is contrary to the prior discussions we have had with CDFG regarding vegetated swales. During a November site visit with CEC and CDFG, the CEC requested that creosote bush-big galleta grass association be considered a special vegetation community (not waters of the State). CDFG then requested that we map all vegetated swales and that they would consider them jurisdictional, but not consider them significant aquatic features that would require mitigation (Personal Communication with Craig Weightman, Senior Environmental Scientist CDFG Inland Deserts Region, Magdalena Rodriguez, Environmental Scientist CDFG Inland Deserts Region, Susan Sanders, Biologist, CEC, and Carolyn Chainey-Davis,Consulting CEC Biologist. November 2009). The swales are generally poorly defined features characterized by low volume, infrequent or short duration flow and are usually shallow topographical features in the landscape that may convey water across upland areas during and following storm events. It is unlikely that these swales convey runoff every year, but there is evidence, through hydrological indicators, that they move surface water across the landscape. However, the swales abate into the landscape prior to reaching and connecting into a more prominent watercourse (e.g., the McCoy Wash).

Page C.2-149, Condition of Certification BIO-23

This condition requires a Decommissioning and Reclamation Plan. PVSI agrees that such a plan is required by federal regulations but does not believe that it can prepare a plan now to restore the site to natural conditions. The full disturbance area will have been mitigated by the Conditions of Certification and therefore the only requirement for such a plan is BLM administering regulations. The ultimate decision of what land use to which the site should be reclaimed lies with BLM. PVSI requests the details of the plan be administered by BLM and has modified the Condition accordingly.

BIO-23 Upon Project closure the Project owner shall implement a final Decommissioning and Reclamation Plan ~~to remove the engineered diversion channels from~~ ***for*** the Project site. ~~The goal of the plan shall be to restore the site's topography and hydrology to a relatively natural condition and to establish native plant communities within the Project Disturbance Area~~. The ~~Channel~~ Decommissioning and Reclamation Plan shall include a cost estimate for implementing the proposed decommissioning and reclamation activities, and shall be consistent with the guidelines in BLM's 43 CFR 3809.550 et seq., subject to review and revisions from BLM's Authorized Officer ~~and the CPM~~ in consultation with USFWS and CDFG.

Verification: ***At least*** ~~No less than~~ 30 days ~~from publication of the Energy Commission Decision or the Record of Decision, whichever comes first,~~ ***prior to the start of construction*** the Project owner shall provide to BLM's Authorized Officer ~~and the CPM an agency-approved final~~ ***draft*** ~~Channel~~ Decommissioning and Reclamation Plan. ***The plan shall be finalized prior to the start of commercial operation and reviewed every five years thereafter and submitted to the BLM's Authorized Officer for approval.*** Modifications to the approved ~~Channel~~ Decommissioning Plan shall be made only after approval from BLM's Authorized Officer ~~and the CPM, in consultation with USFWS, and CDFG~~.

~~No more that 10 days~~ ~~***p***~~*P**rior*** to initiating Project-related ground disturbance activities the Project owner shall provide financial assurances to BLM's Authorized Officer ~~and the CPM~~ to guarantee that an adequate level of funding would be available to implement measures described in the ~~Channel~~ Decommissioning and Reclamation Plan***, consistent with the provisions set forth in 43 C.F.R. sections 2805.12 and 3809.500-.599.***

CULTURAL RESOURCES

Page C.3-48, Last Paragraph

Staff states that it will be including into the inventory a private parcel that PVSI may be acquiring. PVSI will not be impacting this property as it will be outside the current project boundaries, will not be disturbed, and therefore there can be not potential impact to cultural resources that may exist on that property. Staff should not include this property within the inventory.

Page C.3-89, Section 3.5.1.3.7.3.2

In Section C.3.5.1.3.7.3.2, Staff identifies three cultural landscapes as assumed-eligible historic districts. PVSI proposed that the resources within the BSPP be understood with reference to four broad interpretive landscapes, which were clearly described as being distinct from historic districts as defined by law for cultural resources management purposes. Staff suggests that PVSI interpret and mitigate any contributors to the three cultural landscapes/historic districts described in Section C.3.5.1.3.7.3.2, but Staff does not identify the boundaries of the landscapes, nor does Staff specify the contributors to those landscapes. PVSI requests further clarification on how these districts would be defined, if applicable, and the resource attributes Staff anticipates will be included.

Page C.3-108, Section C.3.5.2.3.3

Staff also suggests that the mitigation measures outlined in Section C.3.5.2.3.3 be included in the Programmatic Agreement (PA), and thereby become conditions of certification. In general terms, PVSI accepts the mitigation measures proposed by Staff. PVSI also supports the creation of a project-specific cultural resources PA under the direction of the Bureau of Land Management. Nevertheless, there are a few issues where PVSI requests clarification.

According to the SA/DEIS, based on the basis of current information, Staff was unable to determine whether any of the 234 identified cultural resources within the BSPP survey area are eligible or ineligible for nomination to the NRHP or CRHR. Staff argues that PVSI's mitigation recommendations are "inadequate" under the CEC-defined "Approach 3" to the treatment of cultural resources, but suggests that these recommendations would be acceptable under a "more typical approach to determining what resources are significant" (Section C.3.5.2.2). PVSI requests that Staff clarify how the choice of Approach 3 substantively changes the threshold of eligibility for archaeological sites.

Due to Staff's inability to assess the significance of cultural resources on the basis of existing Class III survey data, Staff assumes the eligibility of all sites within the Project APE. Further, Staff suggests that under Approach 3 "the project's impacts to all assumed register-eligible resources would have to be mitigated by means of avoidance or mitigation in the form of data recovery" (Section C.3.5.1.3.7). This understanding of mitigation under Approach 3 appears different from the language used in the November 24, 2009 letter wherein the CEC described Approaches 1, 2, and 3 for the BSPP. In that letter, the CEC specified that sites assumed eligible under Approach 3 would be mitigated with a "phased treatment plan" through which most sites would be mitigated without full data recovery. As specified in Staff's proposed mitigation measures (Section C.3.5.2.3.2), some sites may require "no additional field work," only the revising of site record forms under Staff and BLM guidance. In addition, as proposed by Staff, some sites may require further archival research, but limited or no additional field work.

HAZARDOUS MATERIALS

Page C.4-19, Condition of Certification HAZ-1

A revised list of Hazardous Materials is included in the Attachment 1and PVSI request this table replace the table contained in Appendix A.

Page C.4-19, Condition of Certification HAZ-4

Staff assessed the properties of Therminol VP-1® HTF and reviewed the record of its use at SEGS Stations 8 and 9 at Harper Lake, California. As a result of this review, Staff has recommended the placement of additional isolation valves in the HTF pipe loops throughout the solar array, which is postulated to add to the safety and operational integrity of the system by allowing a loop to be closed if a leak develops in a ball joint, flex-hose, or pipe. To this end, Staff proposes Condition HAZ-4, which requires the project owner to install manually and remotely operated isolation valves in the HTF pipe loops such that the volume of a total loss of HTF from the isolated loop will not exceed 600 gallons, and Condition of AQ-SC9, item H, which requires that pressure sensing equipment be installed that is capable of sensing a major rupture or spill within the HTF network.

PVSI has several objections to this Condition. First, HAZ-4 would result in a substantial parasitic electrical burden on the BSPP and would require a significant design change from the current industry standard, which specifies the use of manually-controlled valves on the loops at the headers only. The proposed HTF loops contain about 1,250 gallons of HTF, which is the current standard. The 600-gallon volume of HTF stated in the Condition represents the volume in a loop of various older solar collector designs from the late eighties and early nineties. Since then, the modern more efficient solar collector HTF loops contain about twice as much fluid. While we agree that isolation capacity should be provided for each loop; the HTF loops should reflect the modern design standard of about 1,250 gallons, rather than the older, 600-gallon capacity as proposed by the CEC.

Further, the use of remotely operated isolation valves in HTF headers does not represent a current industry design standard. Remotely operated isolation valves are extremely expensive and are not demonstrably affective in isolating a pipe break, and would be difficult to implement on a small bore line coming off a pumped header. Current operating solar thermal plants (e.g., Kramer Junction SEGS) do not have this requirement. Their maintenance program has been successful at preventing leaks since they perform daily inspections of the system. The Applicant believes that these remotely operated valves do not add substantially to safety or control.

HAZ-4 The project owner shall place an adequate number of isolation valves in the Heat Transfer Fluid (HTF) pipe loops so as to be able to isolate a solar panel loop in the event of a leak of fluid such that the volume of a total loss of HTF from that isolated loop will not exceed ~~600~~, ***1,250*** gallons. These valves shall be actuated manually ~~and remotely~~. The engineering design drawings showing the number, location, and type of isolation valves shall be provided to the CPM for review and approval prior to the commencement of the solar array construction.

Pages C.4-20 and 21, Condition of Certification HAZ-6

In order to determine the level of security necessary, the Energy Commission staff used an internal vulnerability assessment decision matrix modeled after the U.S. Department of Justice Chemical Vulnerability Assessment Methodology (July 2002), the NERC 2002 guidelines, the U.S. Department of Energy VAM-CF model, and U.S. Department of Homeland Security regulations published in the Federal Register (Interim Final Rule 6 CFR Part 27). Staff determined that the BSPP would fall into the “low vulnerability” category, so Staff proposed that certain security measures be implemented but did not propose that the project owner conduct its own vulnerability assessment. The application by Staff of their internally derived vulnerability assessment to the BSPP is appreciated by PVSI, however, it is viewed as general guidance.

In addition, Staff had concluded that “Neither the chemical constituents of Therminol VP-1 (diphenyl ether and biphenyl) nor other chemicals proposed to be used and stored at this proposed power plant are on the DHS Chemicals of Interest list and thus this power plant would not be covered by the CFATS regulation.” Even so, Staff believes that all power plants under the jurisdiction of the Energy Commission should implement a minimum level of security consistent with the guidelines they listed in **HAZ- 6**.

The proposed BSPP facility is located approximately 8 miles west of a population center and approximately two miles north of any major roadways in a remote area of the desert. There is one main access road proposed for the facility which will be secured by a gate. The entire site was chosen due to its relatively flat topography which will enhance visibility of the surrounding area by facility personnel. It is unlikely that attempts at unauthorized access, if any, would go un-challenged.

The admitted Staff determination of "low vulnerability" combined with the fact that no reportable quantities of the chemicals of interest will be stored at the facility do not support the onerous requirements put forward by in the Condition of Certification HAZ-6. Although highly unlikely, if the facility was subject to a security breach that took it offline, it would not meet the criteria of a nationally significant event as the electric grid is replete with redundancies. This is one of the major criteria of the U.S. DOJ Chemical Vulnerability Assessment Methodology used to determine the level of security a facility should employ.

PSVI agrees that the proposed facility should implement certain security measures. PVSI also fully recognizes the significant investment it is making and the value of the renewable energy to be produced and would not leave the proposed facility with inadequate security. As such, PSVI intends to provide security commensurate with what is required to protect property and personnel. The enormity of the proposed facility makes any offsite impacts in the event of an incident highly unlikely, as already discussed in the public health risk assessment submitted in the AFC. PSVI agrees to Items 1 through 9 of the recommended Operation and Security Plan, however PSVI disagrees with the requirements in item 10 to include cameras or breach detectors around the entire site. They are neither minimal, nor necessary and this is more appropriate to a natural gas or nuclear facility, and is less applicable/feasible for the solar plant being proposed. PSVI requests that item 10 in HAZ-6 be amended as follows.

10. Additional measures to ensure adequate perimeter security consisting of either:
    A. security guard(s) present 24 hours per day, 7 days per week; **or**
    B. power plant personnel on site 24 hours per day, 7 days per week,

    and one of the following: perimeter breach detectors **or** CCTV able to view 100% of the ~~site~~ ***entrance gate(s) and the power block area for each unit*** ~~fenceline~~.

LAND USE, RECREATION AND WILDERNESS

Pages C.6-10 and 11, Riverside County Airport Land Use Compatibility Plan

This section of the SA/DEIS concludes that the BSPP would be incompatible with the Riverside County Airport Land Use Compatibility Plan (Plan) and that the BSPP is required to be reviewed by the Riverside County Airport Land Use Commission (ALUC). As acknowledged by the ALUC in its letter dated January 19, 2010 to the CEC, the ALUC is preempted by federal law and therefore the ALUC does not have jurisdiction to review the BSPP. Notwithstanding this preemption, PVSI has applied to the Riverside County Airport Land Use Commission for an advisory opinion regarding compatibility. That application was docketed on March 3, 2010.

In that application, PVSI included an analysis supporting compatibility and addressing the issues raised by the ALUC. The SA/DEIS should acknowledge that in fact, power generation, substation and transmission lines are not expressly prohibited in any of the Airport Zones identified by Staff. In fact the ALUC Plan allows the BSPP structures to be constructed subject to conditions to ensure that the structures will not interfere with airport operations. The ALUC, in recognizing that it lacks jurisdiction over the BSPP and operations on federal land, requested that if the CEC or BLM elected not to seek an advisory opinion that the BSPP be subject to the following conditions to ensure compatibility and protect airport operations.

> In the event that the Energy Commission and/or the Bureau of Land Management decide to conduct airport compatibility review for this project without utilizing the ALUC review process, ALUC staff would recommend that the project be subject to the above "standard" condition, supplemented by the following special conditions:
>
>> If the mirrors are mounted on a framework, such framework shall have a flat or matte finish so as to minimize reflection of sunlight.
>>
>> In the event that any incidence of glare or electrical interference affecting the safety of air navigation occurs as a result of project operation, the permittee shall be required to take all measures necessary to eliminate such glare or interference.

The standard condition the ALUC recommends is as follows:

> The following uses shall be prohibited:
>
> (a) Any use which would direct a steady light or flashing light of red, white, green, or amber colors associated with airport operations toward an aircraft engaged in an initial straight climb following takeoff or toward an aircraft engaged in a straight final approach toward a landing at an airport, other than an FAA-approved navigational signal light or visual approach slope indicator.
>
> (b) Any use which would cause sunlight to be reflected towards an aircraft engaged in an initial straight climb following takeoff or towards an aircraft engaged in a straight final approach towards a landing at all airport.
>
> (c) Any use which would generate smoke or water vapor or which would attract large concentrations of birds, or which may otherwise affect safe air navigation within the area.
>
> (d) Any use which would generate electrical interference that may be detrimental to the operation of aircraft and/or aircraft instrumentation.

While PVSI is scheduled to meet with and is cooperating with the ALUC voluntarily, the Staff can conclude that the BSPP is compatible with the ALUC Plan with incorporation of the above restrictions into a Condition of Certification. The analysis demonstrating the BSPP can comply with these restrictions is included in the Application docketed on March 3, 2010.

Page C.6-22, Section 6.8.2, Wilderness, Areas of Critical Environmental Concern (ACEC) and Recreation

Staff concludes that the BSPP will not have a direct impact to recreation and wilderness resources but concludes that the Project will contribute to loss of recreation and wilderness resources. Staff then concludes with no supporting analysis that this impact is significant and unavoidable under CEQA. Staff should acknowledge the vast recreation and wilderness opportunities within the general region (the Colorado and Mojave desert areas of southern California) that would give the public far greater outdoor experiences than those that could be obtained on the BSPP site which is located near the City of Blythe, near the I-10 freeway and near an operating airport. PVSI believes that the BSPP will not contribute to any significant impact related to loss of recreational or wilderness opportunities when considered in context of the regional opportunities available to the public.

NOISE AND VIBRATION

Pages C.7-17 and 18, Condition of Certification NOISE-4

Condition NOISE-4 establishes a requirement for mitigation if noise levels during operation exceed an average of 40 dBA LEQ at the nearby LT monitoring location

As discussed in the AFC, the 40 dBA Leq is the modeled plant daytime average hourly noise level; when this value is added to the measured daytime average hourly noise level of 45 dBA Leq, the resultant noise level is 46 dBA Leq. The County daytime noise limit at a residence is 55 dBA. Therefore, the anticipated daytime plant noise with ambient noise is substantially less than the County threshold (by 9 dBA). Also the increase in ambient with plant noise is less than the CEC threshold for a significant noise impact of an increase of up to 5 dBA. Since the ambient is 45 dBA, an increase of up to 50 dBA would be below the CEC impact significance threshold.

Noise-4 implies that if the plant noise exceeds the "above value" (40 dBA Leq), mitigation measures are required to reduce noise levels to this limit (40 dBA Leq). The limit to be met is the County's limit of 55 dBA, and up to 5 dBA increase over ambient (45 dBA), which would be 50 dBA. The more stringent of these requirements is the 5 dBA increase threshold, which would mean if the plant noise plus ambient measured at the receptor site (LT) were to exceed 50 dBA; mitigation would be required to reduce the plant noise such that the level at LT is below 50 dBA. PVSI therefore requests that this adjusted threshold be recognized in NOISE-4 and that the condition be revised to read as follows:

NOISE-4 The project design and implementation shall include appropriate noise mitigation measures adequate to ensure that the operation of the project will not cause the noise levels due to plant operation alone, during the daytime hours of 7 a.m. to 10 p.m. to exceed an average of ~~40~~ ***50*** dBA Leq measured at or near monitoring location LT.

Page C. 7-19, Condition of Certification NOISE-6

Staff included Condition of Certification NOISE-6 as a means to ensure compliance with PVSI's original understanding of the Riverside County Noise Ordinance. Upon a closer reading of the ordinance, it is clear that the County Noise Ordinance limitation on construction hours applies ONLY to that construction that would take place within ¼ mile of a residence. The only residence that would be within ¼ mile would be a trailer located southeast of the property boundary and opposite solar plant Unit No. 3. A small portion of the solar field construction along the southeastern edge of the property would be subject to the ordinance. However, construction within the rest of the site including all of the construction within the power blocks would not be within ¼ mile of any residence. Therefore, PVSI recommends the following changes to Condition of Certification NOISE-6.

In addition, PVSI believes that solar collector assembly work within the assembly building would have to be conducted 24 hours per day to meet the construction schedule. To provide a more comfortable work environment, PVSI would also like to allow for certain other activities to be conducted at night, such as concrete pours, pulling wire and welding.

NOISE-6 Heavy equipment operation and noisy construction work relating to any project features ***within ¼ mile of an existing residence*** shall be restricted to the times delineated below, unless a special permit has been issued by the County of Riverside:

Mondays through Fridays: June through September: 6 a.m. to 7 p.m.
October through May: 6 a.m. to 6 p.m. Saturdays: 9 a.m. to 5 p.m.
Sundays and Federal holidays: No Construction Allowed

Haul trucks and other engine-powered equipment shall be equipped with adequate mufflers. Haul trucks shall be operated in accordance with posted speed limits. Truck engine exhaust brake use shall be limited to emergencies.

SOIL AND WATER RESOURCES

Page C.9-77, Section C.9.3.1.2, Colorado River Water

Staff concludes that pumping of groundwater at the site would require an entitlement from the US Bureau of Reclamation (Bureau) to use Colorado River Water. Staff completely ignores the significant precedent within the Commission Decisions and recent Orders. Recently in the Genesis Solar Energy Project, (09-AFC-8) the Committee issued a Decision and Scoping Order directly on point. Staff relies on a portion of that Decision and Scoping Order relating to Commission water policy (Page C.9-89) but ignores the portion of that same Decision and Scoping Order where the Committee found after briefs and hearing that the Accounting Surface is not an applicable law, ordinance, regulation or standard (LORS).

The Decision and Scoping Order is also entirely consistent with prior Commission Decisions. In both the Blythe Energy Project (99-AFC-8) and the Blythe Energy Project Phase II (02-AFC-1) the Commission after evidentiary hearings and briefs, concluded that pumping water in the exact same basin as proposed by the BSPP was not subject to the requirement to obtain an entitlement from the Bureau and those project were authorized to pump 10 times the volume of groundwater proposed by the BSPP. Therefore, Staff has ample precedent, clear Commission direction and physical evidence to conclude that the BSPP would not require an entitlement to use Colorado River Water as the Accounting Surface which is the sole legal authority upon which Staff relies and it has not been adopted and is not an applicable LORS. As described in the Data Adequacy Supplement and in responses to Data Requests, PVSI may pursue legal protection from a future law that may require an entitlement in the future. However, this activity should not be required as part of the either the ROW grant or CEC License.

Page C.9-94, Condition of Certification SOIL&WATER-3

The concept of the accounting surface (Proposed Rule, 43 CFR, Part 415, July 2008) relies on the premise of the River Aquifer. As conceptualized, groundwater below the accounting surface and outside of the floodplain within the River Aquifer is water from the Colorado River under the assumption that it would be the only source for water within the aquifer. The site conceptual model for the Palo Verde Mesa Groundwater Basin presented in the AFC indicated that there were more sources of recharge to the basin than the Colorado River, including mountain front recharge and discharge from the Chuckwalla Valley Groundwater Basin to the Palo Verde Mesa. The concept of the accounting surface in general provides a simplistic hypothesis for the sources of water to a well outside the floodplain and ignores fundamental hydrogeologic principles of groundwater flow and hydrologic cycle. Both available water level and water chemistry data show that the Colorado River could not be the source for groundwater below the BSPP site.

Soil and Water- Figure -1 shows the groundwater elevation for wells from available data gathered from 2000 to 2006. The water level contours and groundwater flow lines show that water below the Project site is from up-gradient sources within the McCoy Watershed and that there is a groundwater divide coincident with the flood plain and mesa where water from the river mixes with water from the McCoy Watershed. The water level map also shows that water from Chuckwalla Valley Groundwater Basin flows eastward into the Palo Verde Mesa and mixes with water from the Mesa eventually mixing with groundwater from the Colorado River in the central and southern portion of the flood plain. The groundwater flow lines indicate that groundwater pumping for the Project would preferentially draw water from up-gradient areas which would be from the McCoy Watershed.

The available geochemical data also support the conceptual model that water below the site is from a source in the McCoy Watershed. **Soil and Water - Figure-2** is a Piper Diagram (Tri-linear plot) of the water types comparing water chemistry from wells near the River and those on the Mesa near the Project site. The data show that there are separate water types with water below the Project site as there is a definite contrast in chloride, and lesser so in sodium and potassium. The concept of different water types is further supported as shown on **Soil and Water - Figures -3 through 6**, which present the available data on total dissolved solids (TDS), chloride, boron and fluoride concentrations for wells in the flood plain and on the mesa. Iso-concentration maps were created using the program SURFER (ver. 8) to provide an assessment of the distribution of TDS and these anion concentrations across the flood plan and mesa. The distribution of TDS and anion concentrations further confirm the presence of a groundwater divide and mixing zone east of the Project site along the flood plain and mesa boundary. Both the TDS, chloride and boron data show clear changes in water chemistry from the flood plain across the mesa, and show a distinctive contrast in water chemistry below the site from that below the flood plain to the east.

Soil and Water - Figures -7 through 13, are transects for two locations from the river and area north of the Project site and through the Project site. The graphs illustrate TDS, chloride, boron and fluoride concentrations with increasing distance away from the Colorado River. They provide additional data showing the changes in water chemistry, and thus water sources for the flood plain and the mesa.

Coupled with the groundwater flow data, the geochemical data provide compelling evidence that water below the Project site is not from the Colorado River, but is from a source in the McCoy Watershed. Because PVSI water use is not impacting the Colorado River, PVSI requests that Condition of Certification **SOIL&WATER-3** be deleted.

Page C.9-95, Condition of Certification SOIL&WATER-4

PSVI has determined that additional wells may be needed for BSPP. Therefore, the following changes are requested to **SOIL&WATER-4**:

SOIL&WATER-4 The Project owner proposes to construct and operate ~~up to two~~ ***up to 10 (ten)*** onsite groundwater ~~production~~ ***supply*** wells that produce groundwater from the Palo Verde Mesa Groundwater Basin (PVMGB). The Project owner shall ensure that the water supply wells are completed in accordance with all applicable state and local water well construction permits and requirements. Prior to initiation of well construction activities, the Project owner shall submit for review and comment a well construction packet to the County of Riverside and fees normally required for the county's well permit, with copies to both the AO and CPM. The Project shall not construct a well or extract and use groundwater ***until a permit has been issued by the County*** and both the AO and CPM provide approval to construct and operate the well. ***Wells permitted and installed as part of pre-construction field investigations that***

subsequently are planned for use as project water supply wells require AO and CPM approval prior to their use to supply water to the project.

Post Well Installation. The Project owner shall provide documentation ***as required under the County permit conditions*** to both the AO and CPM that the well has been properly completed. In accordance with California's Water Code section 13754, the driller of the well shall submit to the DWR a Well Completion Report for each well installed. The Project owner shall ensure the Well Completion reports are submitted. The Project owner shall ensure compliance with all county water well standards and ***the County permit*** requirements for the life of the wells and shall provide the AO and CPM with two (2) copies each of all monitoring or other reports required for compliance with the County of Riverside water well standards and operation requirements, as well as any changes made to the operation of the well.

Verification: The Project owner shall do all of the following:

a. No later than 60 days prior to the construction of the onsite groundwater production wells, the Project owner shall submit to both the AO and CPM a copy of the water well construction packet submitted to the County of Riverside.

b. No later than 30 days prior to the construction of the onsite groundwater production wells, the Project owner shall submit a copy of written concurrence received from the County of Riverside that the proposed well construction activities comply with all county well requirements and meet the requirements established by the county's water well permit program. ***The AO and CPM shall provide approval to the project owner of the well location and operation within 10 days of receipt of the well permit.***

c. No later than 60 days after installation of each well at the Project site, the Project owner shall ensure that the well driller submits a Well Completion Report to the DWR with a copy provided to both the AO and CPM. The Project owner shall submit to both the AO and CPM together with the Well Completion Report a copy of well drilling logs, water quality analyses, and any inspection reports. ***Additionally no later than 60 days after installation of each well the Project owner shall submit documentation to the AO, CPM, and the CRBRWQCB that well drilling activities were conducted in compliance with Title 23, California Code of Regulations, Chapter 15, Discharges of Hazardous Wastes to Land, (23 CCR, sections 2510 et seq.) and that any onsite drilling sumps used for Project drilling activities were removed in compliance with 23 CCR section 2511(c)***

d. During well construction and for the operational life of the well, the Project owner shall submit two copies each to the AO and CPM of any proposed well construction or operation permit changes within 10 days of submittal to or receipt from the County of Riverside.

e. ~~No later than 15 days after completion of the onsite groundwater production wells, the Project owner shall submit documentation to BLM's Authorized Officer, the CPM, and the CRBRWQCB that well drilling activities were conducted in compliance with Title 23, California Code of Regulations, Chapter 15, Discharges of Hazardous Wastes to Land, (23 CCR, sections 2510 et seq.) requirements and that any onsite drilling sumps used for Project drilling activities were removed in compliance with 23 CCR section 2511(c).~~

Page C.9-96, Condition of Certification SOIL&WATER-5

As the engineering design has progressed it has come to PVSI's attention that the amount of construction water estimated for the BSPP was too low. The revised estimate is 4,100 acre feet per year and therefore this condition should be modified accordingly.

SOIL&WATER-5: The proposed Project's use of groundwater during construction shall not exceed ~~3,100~~ ***4,100*** af during the 69 months of construction and 600 afy during operation.

Pages C.9-97-100, Condition of Certification SOIL&WATER-6

SOIL&WATER-6: The Project owner shall submit a Groundwater Monitoring, Mitigation and Reporting Plan to both the AO and CPM for review and approval ***in advance of construction activities and prior to the operation of onsite groundwater supply wells***. The Groundwater Monitoring, Mitigation and Reporting Plan shall provide detailed methodology for monitoring background and site groundwater levels and water quality. Monitoring shall include pre-construction, construction, and Project operation water use. The primary objective for the monitoring is to establish pre-construction and Project related groundwater level and water quality trends that can be quantitatively compared against observed ~~and simulated~~ trends near the Project pumping wells and near potentially impacted existing wells.

A. Prior to Project Construction

1. Monitoring shall commence to establish preconstruction base-line conditions. The monitoring ~~plan and~~ network shall include onsite and offsite water supply wells ~~of monitoring wells may make use of existing wells in the basin~~ that would satisfy the requirements for the monitoring program. ***The monitoring network shall be defined by the groundwater model developed for the AFC as the area predicted to show a water level change of 5 feet or more at the end of construction and at the end of operation. Identified additional wells will be located outside of this area to serve as background monitoring wells. Abandoned wells, or wells no longer in use, that are accessible and provide reliable water level data within the potentially impacted area may also be included as part of the monitoring network. A site reconnaissance will be performed to identify wells that could be accessible for monitoring. As access to these wells is available, historic water level, water quality, well construction and well performance information shall be obtained for both pumping and non-pumping conditions.***

2. As access allows, ~~Ccollect~~ measure groundwater levels from the off-site and on-site wells ***within the network and background wells*** ~~and collect and analyze groundwater samples for TDS, nitrates, ammonia and other constituents as required as part of the CRBRWQCB requirements~~ to provide baseline groundwater levels for ***pre-Project trend analysis***. ~~and water quality concentrations for both on-site and off-site wells. Groundwater samples shall be analyzed by a California Certified Analytical Laboratory.~~

3. Construction water level maps ~~Map TDS data and groundwater levels within the PVMGB~~ from the groundwater data collected prior to construction. Update trend plots and statistical analyses, as data is available.

B. During Construction:

1. Collect water levels ~~and water quality concentrations~~ within the monitoring network on a quarterly basis throughout the construction period and at the end of the construction period. Perform statistical trend analysis for water levels ~~and the water quality data~~. Assess the significance of an apparent trend and estimate the magnitude of that trend.

C. During Operation:

1. On a quarterly basis for the first five years of operation, collect water level measurements ~~and water quality data~~ from the wells identified in the groundwater monitoring program to evaluate operational influence from the Project. Quarterly operational parameters (i.e., pumping rate) of the water supply wells shall be monitored. Additionally, quarterly groundwater use in the PVMGB shall be estimated.

2. On an annual basis, perform statistical trend ***analysis*** for water levels and the water quality data. Analysis of the significance of an apparent trend shall be determined and the magnitude of that trend estimated. Based on the results of the statistical trend analyses, the Project owner shall determine if the Project pumping has induced a drawdown in the water supply at a level of 5 feet or more below the baseline trend.

3. If water levels have been lowered ***below 5 feet*** from the pre-site operational trends, and monitoring data provided by the Project owner show these water level changes are different from background trends and are caused by Project pumping, then the Project owner shall provide mitigation to the well owner(s) if impacted. Mitigation shall be provided if the both the AO and CPM's inspection of the well monitoring data confirms changes to water levels and water level trends relative to measured pre-project water levels, and the well (private owners well in question) yield has been lowered by ***5 feet or more*** Project pumping. The type and extent of mitigation shall be determined by the amount of water level decline and site specific well construction and water use characteristics. The mitigation of impacts shall be determined as follows:

a. If Project pumping has lowered water levels ***by 5 feet or more*** from the background trend and is can be shown and increased pumping lifts, increased energy costs shall be calculated. Payment or reimbursement for the increased costs shall be provided at the option of the affected well owner ***on an annual basis***.

b. If groundwater monitoring data indicate Project pumping has lowered water levels below the top of the well screen, and the well yield is shown to have decreased by 10% or more ***of the pre-Project*** ~~initial~~ ***average seasonal*** yield, compensation shall be provided for the diagnosis and maintenance to treat and remove encrustation from the well screen. Reimbursement shall be provided at an amount equal to the customary local cost of performing the necessary diagnosis and maintenance for well screen encrustation.

Should the well yield reductions be recurring, the Project owner shall provide payment or reimbursement for periodic maintenance throughout the life of the Project. If with treatment the well yield is incapable of meeting 110% of the well owner's maximum daily demand, dry season demand, or annual demand the well owner should be compensated by reimbursement or well replacement as described under Condition 3.c.

~~Should well yield reductions be reoccurring, the Project owner shall provide payment or reimbursement for either periodic maintenance throughout the life of the Project or, if treatment is anticipated to be required more frequently than every 3-5 years, replacement of the well.~~

c. If Project pumping has lowered water levels to significantly impact well yield or cause casing collapse, payment or reimbursement of an amount equal to the cost of deepening or replacing the well shall be provided to accommodate these effects. Payment or reimbursement shall be at an amount equal to the customary local cost of deepening the existing well or constructing a new well. The demand for water, which determines the required well yield, shall be determined on a per well basis using well owner interviews and field verification of property conditions and water requirements compiled as part of the pre-project well reconnaissance. Well yield shall be considered significantly impacted if it is incapable of meeting ***110*** ~~150~~% of the well owner's maximum daily demand, dry-season demand, or annual demand – assuming the pre-Project well yield documented by the initial well reconnaissance met or exceeded these yield levels. ~~For already low-yielding wells identified prior to Project construction, a reduction due solely to Project pumping of 10% or more below the pre-project yield shall be considered a significant impact. The contribution of Project pumping to observed decreases in observed well yield shall be determined using the groundwater monitoring data collected.~~

d. Electrical cost reimbursement – If the pumping water level falls below a depth of 5 feet from ***the background trend*** ~~an average of the baseline measurements~~ **and** ***is shown to be caused by the Project pumping***, the well owner shall be compensated by the Project owner for the additional electrical costs commensurate with the additional lift required to pump. The water level in the well will be assessed relative to the pumping rate established during the pre-site development period.

e. The Project owner shall notify all owners of the impacted wells within one month of both the AO and CPM approval of the compensation analysis for increased energy costs.

f. Pump lowering – In the event that groundwater is lowered to an extent where pumps are exposed but well screens remain submerged the pumps shall be lowered to maintain production in the well. All costs associated with lowering pumps shall be borne by the Project owner.

g. Deepening of wells – If the groundwater is lowered enough that well screens are exposed, pump lowering is not an option. In this case, the wells shall be deepened or new wells constructed. All costs associated with deepening existing wells or constructing new wells shall be borne by the Project owner.

4. After the first five-year operational and monitoring period both the AO and CPM shall evaluate the data and determine if the monitoring program water level measurements ~~and water quality sampling frequencies~~ should be revised or eliminated. Revision or elimination of any monitoring program elements shall be based on the consistency of the data collected. The determination of whether the monitoring program should be revised or eliminated shall be made by the both the AO and CPM.

5. At the end of every subsequent five-year monitoring period, the collected data shall be evaluated by the both the AO and CPM and they shall determine if the sampling frequency ~~and water quality sampling~~ should be revised or eliminated.

6. During the life of the Project, the Project owner shall provide to the both the AO and CPM all monitoring reports, complaints, studies and other relevant data within 10 days of being received by the Project owner.

Verification: The Project owner shall do all of the following:

1. ***At least 60 days prior to operation of the site groundwater supply wells*** ~~Project construction~~, the Project owner shall submit to the both the AO and CPM, the Groundwater Monitoring, Mitigation and Reporting Plan, that will include ~~a comprehensive report presenting all~~ the data and information required in item A above. ***The AO and CPM will provide comments to the plan 15 days following submittal, and the final plan shall be approved 15 days prior to operation of the site groundwater supply wells.***

2. The Project owner shall submit to the both the AO and CPM all calculations and assumptions made in development of the report data and interpretations.

3. During Project construction, the Project owner shall submit to the both the AO and CPM quarterly reports presenting all the data and information required in item B above. ***The quarterly reports shall be provided 30 days following the end of the quarter.***

4. The Project owner shall submit to the both the AO and CPM all calculations and assumptions made in development of the report data and interpretations.

5. ***No later than March 31 of each year of construction or*** 60 days prior to Project operation, the Project owner shall provide to the both the AO and CPM for review and approval, documentation showing that any mitigation to private well owners during Project construction was satisfied, based on the requirements of the property owner as determined by the both the AO and CPM.

6. During Project operation, the Project owner shall submit to the both the AO and CPM, applicable quarterly and annual reports presenting all the data and information required in item C above. ***Quarterly reports shall be submitted to the AO and CPM 30 days following the end of the quarter. The 4th quarter report shall serve as the annual report, and will be provided on January 31 in the following year.***

7. The Project owner shall submit to the both the AO and CPM all calculations and assumptions made in development of report data and interpretations, calculations, and assumptions used in development of any reports.

8. The Project owner shall provide mitigation as described in item C.3 above, if the both the AO and CPM's inspection of the monitoring information confirms changes to water levels and water level trends relative to measured pre-project water levels, and well yield has been lowered by Project pumping. The type and extent of mitigation shall be determined by the amount of water level decline and site specific well construction and water use characteristics. The mitigation of impacts will be determined as set forth in item C.3 above.

9. If mitigation includes monetary compensation, the Project owner shall provide documentation to the both the AO and CPM that compensation payments have been made by March 31 of each year of Project operation or, if lump-sum payment are made, payment is made by March 31 following the first year of operation only. Within 30 days after compensation is paid, the Project owner shall submit to the both the AO and CPM a compliance report describing compensation for increased energy costs necessary to comply with the provisions of this condition.

10. After the first five year operational and monitoring period, the Project owner shall submit a 5 year monitoring report to both the AO and CPM that submits all monitoring data collected and provides a summary of the findings. Both the AO and CPM will determine if the water level measurements and water quality sampling frequencies should be revised or eliminated.

Page C.9-101, Condition of Certification SOIL&WATER-10

PVSI suggest the Verification to this condition be modified as follows.

> **Verification:** At least ~~90~~ ***30*** days prior to the start of ***construction*** ~~site mobilization~~, the Project owner shall submit decommissioning plans to the AO and CPM for review and approval. The Project owner shall amend these documents as necessary, with approval from the AO and CPM, should the decommissioning scenario change in the future

Page C.9-102, Condition of Certification SOIL&WATER-11

The Verification to this Condition of Certification requires submittal of a Revised Project Drainage Report no less than 30 days after the CEC issues the License. PVSI requests this be modified consistent with other conditions that measure the verification timeline "prior to" an activity such as mobilization or construction. We request the Verification be modified as follows.

> **Verification:** The Project owner shall submit a Revised Project Drainage Report with the 30% Grading and Drainage Plans to both the AO and CPM for their review and comments 30 days ***prior to construction*** ~~after project certification~~. The owner will address comments provided by both the AO and CPM until approval of the report is issued. All comments and concepts presented in the approved Revised Project Drainage Report with the 30% Grading and Drainage Plans will be included in the final Grading and Drainage Plans. The Revised Project Drainage Report and 30% Grading and Drainage Plans shall be approved by both the AO and CPM.

Page C.9-103, Condition of Certification SOIL&WATER-13

The Project slopes are designed 3:1, and as designed are sufficient to allow tortoise access up and down the slope and therefore the condition should be revised eliminating the requirement for a 4:1 slope. Revision of the design to 4:1 would not significantly improve the ingress and egress of tortoise movement, though would increase the grading volume, disturbance area and concomitantly the construction water supply. The increase in water supply relative to the minor change in tortoise access is not warranted.

Page C.9-104-C.9-105, Condition of Certification SOIL&WATER-14

PVSI recommends the following modification to this condition to more accurately reflect the current design.

> E. Earthen berms used on the outside of collector channels to guide flow to discreet points of discharge into a channel ~~shall not~~ ***may*** be utilized in lieu of soil cement on the outside bank of collector channels. ~~Offsite flows shall discharge directly into collector channels.~~ ***If earthen berms are utilized, the discreet points of discharge shall be protected against erosion by the use of soil cement.***

Pages C.9-108-110, Condition of Certification SOIL&WATER-17

This Soil and Water Condition is attendant to **SOIL&WATER**-3 by providing a mechanism to evaluate the quantity of water diverted from the Colorado River by Project pumping. As described under **SOIL&WATER**-3, there is ample evidence that groundwater drawn below the Project site is not related to the Colorado River. The information provided in response to **SOIL&WATER**-3 presents the site conceptual model for the Project site and this portion of the Palo Verde Mesa Groundwater Basin. As the conceptual model developed under **SOIL&WATER**-3 revealed both groundwater flow and geochemical data indicated that the water below the site is from a principal source in the McCoy watershed not the Colorado River. Groundwater flow data would suggest that pumping from the Project site would tend to draw groundwater preferentially from a source in the McCoy watershed.

While the numerical modeling program would provide a mechanism for more sophisticated analysis, it would be developed to reflect the conceptual site model and simulate the water level and geochemical trends therein. As such, more sophisticated analysis would likely not produce a different conclusion, that the groundwater below the site is sourced from the McCoy Watershed and not the Colorado River. Because the study that would be required by this condition would not likely change this conclusion, PVSI requests that Condition SOIL&WATER-17 be deleted.

Page C.9-112, Conclusions, Last Bullet

Staff states that it cannot complete its analysis until it receives, "A finding by the USACE of whether the ephemeral drainages on the Project site are jurisdictional waters of the U.S." PVSI has outlined in its Jurisdictional Determination Report why the drainages are not jurisdictional waters of the U.S. Notwithstanding that analysis, Staff can easily conclude that the Project would comply with Section 404 of the Clean Water Act by including a condition that the project owner shall obtain a Section 404 permit prior to filling of any jurisdictional water of the U.S. if such permit is required by the USACE. The verification could include the requirement for the project owner to either produce the permit or a determination that no permit is required from the USACE. That determination is simply not needed now and this approach is consistent with the CEC Decisions issued in the last few decades.

TRAFFIC AND TRANSPORTATION

Page C.10-16, Second Paragraph

Staff asserts that the BSPP must be reviewed by the Riverside County Airport Land Use Commission (ALUC). While BSPP has filed an application for review to the ALUC, this has been done voluntarily as PVSI and the ALUC agree that it does not have jurisdiction over activities on federal land (see also discussion above under Land Use). PVSI agrees with Staff that the FAA review is required and has submitted all applicable forms for FAA review of the transmission poles and tall structures within the appropriate zones.

Pages C.10-16 and 17, Air Cooled Condensers

Staff has performed a thermal plume analysis and concludes the ACC is capable of causing upward plumes with velocities that exceed 4.3 m/s at considerable heights. PVSI's consultants have reviewed Staff's basis and analysis for this conclusion and disagree. Specific comments related to Staff's analysis contained in Appendix TT-1 of the SA/DEIS are provided below.

PVSI believes that the Staff analysis used to develop their estimate of vertical plume velocities above the ACC is faulty for three reasons:

- The model used by Staff is an inappropriate model because the release characteristics of the plume produced by an ACC do not fit the assumptions used to develop the plume rise model used in the Staff analysis. Consequently, the Staff estimate of the expected vertical velocity profile of the ACC plume is invalid.
- The Staff employed incompatible assumptions in their modeling analysis of plume rise above an ACCACC that make the analysis unrealistic rather than conservative.
- The significance criteria used in the SA/DEIS to define a hazard to general aircraft from plume turbulence is specified by the agency developing the criteria as valid at 360 feet above the ground. The SA/DEIS does not provide any justification for extending the applicability of this significance criteria up to nearly 2,000 feet above the ground.

These three issues are discussed further below:

Inappropriate Model

The basic model used by Staff to estimate plume rise above the ACC is based on the general equations documented by Gary Briggs[3] and implemented in one version or another in most current models that make estimates of plume rise. A key assumption in standard plume rise models for buoyant plumes is that plume rise is a function of

[3] Gary A. Briggs, Chapter 3. Plume Rise Predictions, in "Lectures on Air Pollution and Environmental Impact Analysis", American Meteorological Society, Duane Haugen, Editor, Boston,1976.

downwind distance raised to the power of 2/3 (commonly called the "2/3 Law"). This assumption does not appear to hold for a plume from an ACC.

In 2008, the CEC contracted with the University of Stellenbosch, South Africa, to perform computational fluid dynamic (CFD) modeling of a typical air cooled steam condenser (same type of unit as the BSPP ACC) to determine the effectiveness of cooling as a function wind speed and wind direction[4]. The modeling was performed using the FLUENT model. Modeling using CFD methodology is the premier methodology available today to simulate problems in fluid mechanics such as airflow around obstacles and motion in a fluid. Based on preliminary review of figures of simulated plumes provided in this CEC report, it appears that the trajectory of the thermal plume from an ACC, as computed by FLUENT, rises with a plume rise to downwind distance ratio dependency ranging from an exponent of 0.4 for low wind speed perpendicular to the long axis of the ACC flow to nearly 0.8 for higher along axis wind speeds. The 2/3 Law assumes a constant exponent of 0.67.

The FLUENT generated plume appears to be a mixture of momentum and buoyancy forcing accounting for a mixture of momentum dominated jet flow that typically obeys a 1/3 power law and the buoyancy dominated plume rise that obeys the 2/3 Law.

A basic assumption in the Briggs' formulation of plume rise is that the plume is axisymmetric, or symmetrical around the vertical axis of rise. However, the ACC is a structure that prevents symmetry about the vertical axis. Because the linear structure of the heat exchangers is a linear A-frame arrangement, there is direction-dependent entrainment of ambient air into the plumes that leads to direction-dependent rise and turbulence fields surrounding the plume. These non-symmetrical influences are not accounted for in the Briggs' formulation. In addition, the A-frame lattice and cooling tubes/fins of the heat transfer surface essentially creates a diffuser above the ACC that tends to distribute vertical flow evenly across the entire surface of the ACC, a surface of approximately 100m x 75m, compared to a typical power plant stack that may have a diameter of 10m.

Based on the above preliminary analysis, it appears that the Briggs' formulation of plume rise is inadequate for simulating the rise, and vertical velocity profile, in a plume above an ACC because of violations of the basic assumptions inherent in the model. To simulate plume rise accurately above an ACC, a fully developed non-axisymmetric integral plume rise model would be needed to model the rate of vertical wind speed and turbulence decrease with height above the unit.

Incompatible Modeling Assumptions

The Staff modeling of plume rise from an ACC includes two incompatible assumptions. First, full load on the power block is assumed. Since the BSPP is a solar power plant, full load can only occur during the day with the sun is shining. The Staff modeling also assumes that the wind speed is calm, and is calm through an approximate 2,000-ft depth of the surface boundary layer. During the day time when there is strong incoming sunlight that would allow a solar power plant to operate at full load, there would also be would have significant heating of the ground surface and likely strong to intense thermal convection

[4] J. A. van Rooyen and D. G. Kröger, Performance Trends of an Air-Cooled Steam Consenser Under Windy Conditions, CEC-500-2007-124, University of Stellenbosch, South Africa, May 2008

from the desert floor. The wind flow under such conditions would be variable and light, but not calm. The strong convection after sunrise would quickly destroy any residual shallow surface layer with calm winds that formed during the preceding evening.

At night with limited gradient winds, a layer of calm winds can form, and depending upon meteorological conditions, the calm layer could extend to a moderate height above the ground. However, there would be no sunlight at this time that would allow for full load on the solar array. While Staff may claim that this is a conservative assumption, it is not a credible worst-case assumption, and hence it is an unrealistic assumption.

Lack of Justification of Modeling Criteria

The CEC vertical velocity significance criteria, 4.3 m/s average vertical wind speed, is based on a draft Australian Aviation Safety circular[5]. In this circular, they give the altitude below which there is a potential hazard for a vertical velocity of 4.3 m/s as 360 ft. The CEC uses the 4.3 m/s criteria but ignores the rest of the circular in its application as to the height at which the vertical velocity can be a hazard. In the circular, the hazard is defined as that which "may cause airframe damage to an aircraft at critical stages of flight, e.g., when approaching to land with flaps extended." The CEC needs to document the hazard presented by a plume at an altitude of 2,000 feet when the vertical plume velocity is 4.3 m/s, as an aircraft would not be in the landing pattern, which at Blythe Airport is 800 ft (see below).

Qualitative Assessment of Turbulence Potential from an ACC

From a simple review of the characteristics of an ACC plume, it is difficult to determine the mechanism that could produce turbulence above the moderate level in the plume above an ACC. The primary energy source in any cooling tower plume is the thermal energy associated with the dissipation of heat (approximately 400 MW for the BSPP) into the ambient air above the facility cooling structure . In the proposed BSPP ACC, this energy is dissipated across an area of approximately 6,700 m^2, compared to the same energy in a wet cooling tower of the same capacity that could be dissipated across an area approximately 3,200 m^2. Thus, the thermal energy density in a wet cooling tower plume is more than twice as great as that in an ACC plume. As wet cooling cooling towers typically do not produce severe turbulence in their plumes, it is not expected that an ACC plume with less than one-half of the thermal energy density will produce turbulence above a moderate level.

The actual air temperature change after passing through the ACC is only 10ºC, spread across 7,500 m^2. The vertical velocity averaged across the top of the ACC is only 4.5 m/s measured at the point of release, just barely above the significance criteria used by the CEC. In general, the turbulence in the plume is driven by the temperature difference (10ºC) and this temperature difference will decrease with height, thus dissipating the available energy for generating turbulence in the plume. Consequently, it is difficult to postulate reasonable meteorological conditions that could lead to an increase in plume turbulence with increasing height above the ACC. In addition, even if there were greater than moderate turbulence in the plume above an ACC, the probability of a light aircraft at the Blythe Airport experiencing that turbulence is very small, as documented below.

[5] Australian Government Civil Aviation Safety Authority Draft Advisory Circular AC 139-05(0), Guidelines for Plume Rise Assessment, October 2003.

Assessment of Flight Patterns with Respect to an ACC

The Blythe Airport is classified as a general aviation airport and operates a VOR approach system. The airport has two intersecting runways, Runway 08/26 and Runway 17/35. The runway designation is the azimuth of the runway in the direction of aircraft motion given in tens of degrees. For example, the most used runway at the Blythe Airport is Runway 26. This refers to an azimuth of 260 degrees or 10 degrees left of due west, and would be the runway in use for aircraft landing or departing to the west. If the motion on the runway were in the opposite direction, the runway would be designated Runway 08 and the azimuth would be 80 degrees, or 10 degrees left of due east. Likewise, Runway 17 is in use when aircraft are landing or departing to the south, and Runway 35 is used for landings or departures to the north.

The 2004 Riverside County Compatibility Plan contains projections of the number of flight operations at the Blythe Municipal Airport projected to 2020. One flight operation consists of either a landing or a takeoff. In 2020, there are projected to be 159 operations per day at the Blythe airport. For piston aircraft, the aircraft most susceptible to potential turbulence from an ACC (ACC), the distribution of operations by time of day is currently 88 percent daytime, 10 percent evening, and 2 percent nighttime. This distribution is not expected to change in the future. The expected operations in 2020 at the Blythe Airport by runway and aircraft type are given in Table TRANS-1.

Table TRANS-1. Projected Daily Operations in 2020 at Blythe Municipal Airport by Runway and Aircraft Type

	Piston Engine	Turboprop	Business Jets	Totals
Runway 8	7.4	0.2	0.2	8
Runway 26	73.9	3.6	4.1	82
Runway 17	44.4	0.5	0.2	45
Runway 35	22.2	0.5	0.2	23
Helicopters				2
Totals	148	5	5	159

Source: Riverside County Air Port Land Use Compatibility Plan, October 2004. Volume 3. Blythe Municipal Airport.

Based on information contained in Volume 3 of the Riverside County Airport Land Use Compatibility Plan (Volume 3 Blythe Airport), the pattern altitude for the airport is 800 feet and it is a left-turn pattern for all runways. Figure TRANS-1 presents a diagram of the traffic patterns for the airport that is anticipated to encompass 80 percent of all flight operations, or approximately 127 operations per day in 2020. The remaining daily flight operations (approximately 32 aircraft operations per day) will occur outside the traffic patterns defined in Figure TRANS-1.

The most used runway at the Blythe Airport is Runway 26 with 50 percent of piston engine aircraft operations, followed by Runway 17, with an additional 30 percent of piston engine aircraft operations. The general approach procedure for Runway 26 is a straight in approach with a 25 degree right of centerline entry into the pattern. The straight-in approach has a descent height of 366 feet. If there is less than one mile visibility at this altitude, the standard procedure is to go around, which will involving climbing back to the pattern altitude of 800 feet and commencing the approach again. For a circling approach to the airport, and with VOR/GPS-A, the descent height is 433 feet, for a visibility of less than one mile.

The approach pattern distribution of flights presented in Figure TRANS-1 does not take aircraft over any part of the solar array field but has some aircraft operating above the right of way (facility boundary). However, in 2020, approximately 32 aircraft operations per day will occur outside the boundary given in Figure TRANS-1. One possible approach that could take aircraft over the solar field and one of the ACCs would be an approach to Runway 17 that would come in from the west over the McCoy Mountains, pass over the BSPP, and make a right turn for a direct landing on Runway 17. While plausible, such an approach and landing would be uncommon given the typical avoidance of pilots to overfly terrain obstacles (i.e., McCoy Mountains) at relatively low altitude, followed by the need for a more rapid descent over the BSPP to get to pattern altitude, and finally the need for a right turn onto final approach, contrary to the designation of the airport as left traffic for all runways.

Based on the projected flight operations for the Blythe airport, the airport traffic pattern defined in Figure TRANS-1, and the approach procedures for the airport, it is unlikely that any aircraft that would overfly the BSPP would be at an elevation of less than 800 feet. Given the small number of daily flight operations anticipated for 2020 that would be outside the general flight pattern in Figure TRANS-1 (approximately 32 flight operations per day), the number of over flights of the BSPP by general aviation aircraft on a given day will be small to zero. Consequently, there is little probability that potential turbulence produced by an ACC at the BSPP would constitute a hazard to general aviation aircraft at the BSPP.

Page C.10-17, Impact of Flash of Light on Pilots

As explained below in the comments on Condition of Certification **VIS-4**, the only geometry that allows for pilots to observe potential flashes of light from the BSPP solar array will be when the pilot is east or west of the solar array and in an approximate direct line from the sun and the solar array. In addition, the intensity of the glare, or specular reflection, is subject to inverse square attenuation with distance from the glare source. The farther the pilot is from the solar array, the weaker the glare becomes by the square of the distance. Beyond a certain distance that will depend on a number of factors including time of day, pilot altitude, clarity of the air, and cloudiness, among other factors), the glare will be so dissipated as to blend into and contribute to the general glow from the linear Heat Conducting Elements (HCEs). As was documented in the AFC, including observations by a CEC Staff member (James Adams) in the Victorville 2 (07-AFC-1) AFC proceedings, from a distance, the solar array looks like a body of water and there is no indication of point sources of glare.

As discussed in the comments on Condition of Certification **VIS-4**, the glare will only occur when the observer is perpendicular to the linear HCE tubing. Consequently, a pilot on the ground at the Blythe Airport will not be able to observe any glare since no location on the airport will be perpendicular to the HCE tubing.

Pilots would potentially be able to observe glare from the solar arrays when east or west of the BSPP, as discussed above. Since the McCoy Mountains are to the west of the BSPP, aircraft are likely to be several miles from the BSPP solar arrays if they are to the west of the airport. Because of this distance, the drop-off in intensity of any potential glare will be significant due the inverse square attenuation and there is unlikely to be any significant glare that would potentially be hazardous. This leaves only aircraft operating from or near Runway 17/35 that would potentially be affected by glare.

As discussed above, and can be calculated from the data in Table TRANS-1, there are an estimated average of 68 flight operations per day in year 2020, of which 88% would be daytime operations, and 43% would be for operations involving Runway 17/35. Assuming that the daytime flights are spread over a 10-hour day, this results in less than three aircraft using Runway 17/35 in any given daytime hour. Given that these operations will tend to follow a set pattern on either arrival or departure, the pattern height and approach glide slope could be used to define the solar geometry (i.e., time of day) at which glare could possibly be observed. Such a geometry of sun-flight profile is unlikely to persist for more than a single hour. Thus, a very small number of pilots could potentially expose themselves to glare at the airport on any given day, and the times and locations of exposure could easily be computed by the geometry of the pattern height, glide slope, and sun angle (time of day), and noted as a NOTAM.

It is less likely that a pilot would be subject to glare from the solar field than what a pilot would experience from non-solar field reflective surfaces such as from a building window in the vicinity of the airport and from windshields, mirrors, and flat surfaces of vehicles traveling along Interstate 10.

Pages C.10-34-36, Condition of Certification TRANS-3

This condition requires coordination between PVSI and Genesis Solar on a traffic control plan. PVSI recommends the following modification as it cannot control over the schedule of a project owned by another company.

2. In conjunction with Genesis Solar/NextEra ***to the extent practicable and if actual construction traffic overlaps***, devise a traffic control plan that:

Page C.10-37, Conclusions

Staff states in the conclusion section that it found unmitigatable impacts due to the BSPP's proximity to the Blythe Airport. However, this conclusion is not supported by Staff's analysis whereby it states that it is working with the ALUC and the Applicant to develop mitigation.

VISUAL RESOURCES

Page C.12-1, Second Paragraph

"Staff concludes that these visual impacts would be significant in terms of three of the four criteria of California Environmental Quality Act (CEQA) Appendix G, and could not be mitigated to less than significant levels and would thus result in significant and unavoidable impacts under CEQA." However, the CEC visual analysis process is highly dependent on photographs of existing conditions and accompanying photographic simulations. The SA/DEIS analysis is based on very crude Google Earth-based simulations (perspective views of the Project site without simulations of Project facilities), with the following statement in each KOP impact discussion. "This perspective was prepared because an appropriate visual simulation was not available at the time this SA/DEIS was prepared." The SA/DEIS does not utilize or even acknowledge that additional simulations were requested of the applicant in Data Requests and were submitted to the CEC on January 13, 2010 while the SA/DEIS was in early stages of preparation.

The SA/DEIS analysis does not provide a sound technical basis for its conclusions. Without photographs and photographic simulations of Project facilities(which were provided to the CEC/BLM in January 2010 as noted above), there is no professional, technical analysis/data to serve as an objective basis for discussion and conclusion about Project visual resources impacts and appropriate Conditions of Certification.

Condition of Certification **VIS-4** requires slatted fencing along the north and south boundaries of Project site because of "glint and glare/"bright spots" concerns. Such fencing would serve no useful purpose and is inconsistent with the optics leading to the production of glare from the mirror array, The production of glare from the mirror array, or in more accurate terminology, specular reflection, is not due to direct reflection of the sun by the parabolic mirror but is due to three sources of light of much lower intensity:

- The reflection of incoming sunlight from a small linear area along the front of the Heat Conducting Element (HCE) that is normal (perpendicular) to the sun and intercepts and reflects a small portion of the incoming sunlight.
- Direct reflection of light from metal components of the parabolic mirror array such as connectors along the HCE tube and structural elements.
- Light that is first refracted and scattered by the glass tube of the HCE that then strikes the mirror and is subsequently reflected outwards in a columnar beam, but at a greatly reduced intensity.

Specular reflection must obey the Law of Reflection, derived from Snell's Law, in which the incoming and outgoing light rays form the same angle of incidence from the normal to the reflecting surface. The mirror arrays at all solar trough power plants are aligned north-south to allow east-west tracking of the sun. The normals for any given HCE tube are therefore east and west of the solar array, and therefore reflections can only occur to the east and west.

The only time specular reflection can occur from the BSPP mirror array and be visible by a ground level observer is when the observer is to the east or west of the mirror, the sun is low on the horizon, to the back of the observer and slightly over the observer's shoulder, and the observer is looking at the point where a perpendicular line from the observer to the HCE intersects the HCE. This means that the glare will not be observable from I-10 to the south of the BSPP and will not be visible from the Blythe Airport to the southeast of the BSPP.

For a properly situated ground level observer, the only time glare would be visible is in the first few hours after sunrise, or before sunset, when the sun is low on the horizon. However, for the BSPP, with the McCoy Mountains immediately to the west, the general public will only be exposed to the potential specular reflections when located to the east of the mirror arrays. As the sun rises in the sky during the morning and the mirrors begin tracking the sun, Snell's Law will not allow a ground level observer to observe the reflection. It is important to reiterate that the reflection (glare) is specular reflection from the HCE tube with lesser amounts of scattered and refracted light, not reflection of the sun from the parabolic mirror.

Figure VISUAL-1 presents a comparison of glare from the Kramer Junction SEGS facility in a photograph taken by Merlyn Paulson of AECOM, and the SA/DEIS photo attributed to Michael Clayton & Associates. The photograph by Mr. Paulson is one of about 200 taken on the same day and represents the photograph with the most intense glare spot. The CEC picture presents a glare that is considerably more intense than in the AECOM photographs. The most plausible explanation for the non-representativeness of the CEC photo is that the CEC photo is over-exposed. If an over-exposure did occur, the light sensor would have been saturated with the result that the apparent size of the glare spot is much larger than actually existed.

The CEC photo was taken from Highway 395 near sunrise looking west, as demonstrated by the horizontal pointing of the mirror and includes a broad expanse of dark pavement in the foreground. The early morning hour indicates relatively low light conditions, as does the relatively dark sky. Because the actual glare spot is small in the frame of the picture, it is unlikely to affect the area-weighted exposure algorithm in the camera and thus the exposure by the camera will be overly influenced by the dark foreground. If the person taking the photograph in such a difficult exposure situation does not adjust the camera settings for the difficult exposure, the autoexposure mode of the camera will likely result in a wide aperture setting based on the general low light and dark foreground. This likely happened with the CEC photograph, resulting in a wider aperture than appropriate for the element in the photograph of interest – the glare spot - with a resulting overexposure of the glare. As a result, the glare is out of proportion from what actual occurred. In addition, the wider aperture will allow more flare in the lens and reflections from the mirror. Note that close examination of Paulson's photo taken with a proper exposure setting contains a small amount of flare around the glare point. An overexposed image would be expected to have considerably more flare in the resultant picture, as is observable in the CEC photo. The probable overexposure and flare in the CEC photo result in an intense spot of light not representative of actual viewing conditions.

The photograph by Paulson was taken with a Nikon D200 camera in shutter priority mode, with the below exposure settings:

Width: 3872 pixels
Height: 2592 pixels
Date: 04/25/2009 8:43:53 A.M.
Camera: Nikon D200
Software: 2.0
Shutter: 1/80
Aperture: f 32.0
Max Aperture: f4.9
Exposure: Shutter priority
Exposure Bias: 0.0
Focal Length: 70.00mm
ISO Speed: 100
Sensing: One-chip color area
Brightness: 0.0

Page C.12-38, Condition of Certification VIS-2

This condition requires revegetation consistent with Condition of Certification BIO-8 but includes the substation which will be constructed, owned and operated by Southern California Edison (SCE) and therefore permitted by the California Public Utilities Commission (CPUC). Therefore we request the reference to siting of the substation be deleted from the condition.

Page C.12-39, Condition of Certification VIS-4

For the reasons discussed above in the PVSI comment concerning page C.12-1, this condition should be deleted.

Page C.12-40, Condition of Certification VIS-5

This condition requires various design components be incorporated but incorporation of these costly measures, according to Staff, will not reduce the visual impacts to less than significant levels. Since Staff believes a Finding of Override is required to License this project, there seems to be no impact or LORS-related reason to incur the costs to implement Condition of Certification VIS-5 and it should be deleted.

It should be noted that most of the design concepts mentioned in the Condition are embodied in other disciplines/Conditions (e.g., retain as much vegetation as possible, use vegetation for screening when possible); some are obvious and already planned (minimize number of buildings and combine functions). The key elements of mitigation for Visual Resources are presented in the other Visual Conditions ((surface treatment, lighting, revegetation, and glare reduction). There is no adequate justification for a possible additional elaborate design review process, particularly one that is largely redundant with other disciplines and mitigation measures.

WASTE MANAGEMENT

Page C.13-28, Condition of Certification WASTE-7

As Staff correctly identifies, there is no applicable LORS that would require the BSPP to comply with this condition. Additionally, with the incorporation of Condition of Certification WASTE-11 the BSPP will not impact local landfills and therefore this condition is not necessary to mitigate any BSPP caused impact. Therefore, WASTE-7 should be deleted.

Page C.13-29 and 30, Condition of Certification WASTE-9

PVSI is cognizant that HTF-affected soils will be characterized as hazardous or non hazardous waste prior to determination of whether the material can be treated at the LTU or must be removed for off-site disposal. Therefore, HTF-affected soils will be relocated to a temporary staging area in the LTU and characterized consistent with U.S. Environmental Protection Agency (EPA) protocols. Soil samples of HTF-affected soil will be collected in accordance with the EPA's current version of the manual "Test Methods for Evaluating Solid Waste" (SW-846) and the waste material will be characterized in accordance with State and Federal requirements. Soil samples will be analyzed for HTF constituents (Biphenyl and Diphenyl Ether) using modified EPA Method Modified 8015 as indicated by Staff. If the soil is characterized as a hazardous waste (e.g., at a site specific level likely to be on the order of 10,000 mg/kg or greater), the impacted soils will be transported from the site by a licensed hazardous waste hauler for disposal at a licensed hazardous waste landfill or treatment storage and disposal facility (TSDF).

Based on the classification practice and management of a similar waste stream at the Kramer Junction Solar Electric Generating System (SEGS) facility in Kern County, the DTSC issued a letter dated April 4, 1995, stating that soil contaminated with HTF "poses an insignificant hazard" and classifies the waste as non-hazardous for soils with a concentration of less than 10,000 mg/kg HTF pursuant to CCR Title 22, Section 66260.200(f). Given the formulation of HTF has not changed significantly since this determination, it is anticipated that future waste characterization at BSPP will yield a similar result. However, DTSC has indicated that classification of Project HTF-contaminated soils as hazardous or non-hazardous is a site-specific decision that will be made by DTSC.

All HTF-affected soil classified as a hazardous waste will be removed for the site for proper off-site disposal; therefore the material in the LTU will be managed as a non-hazardous "designated waste" as defined in CCR Title 23, Chapter 15, Section 2522. Based on waste discharge requirements for similar sites, soil containing HTF in concentrations less than 100 mg/kg will not be regulated as a waste and could be reused as fill on site.

Based on the historical information available from long operating solar facilities utilizing similar technology and materials and an understanding of the properties of HTF, precedent has been set for the management of HTF-affected soils. As such PSVI feels that certain elements of **WASTE-9** are onerous and unnecessary with respect to some of the reporting requirements and recommends the condition be revised as follows:

WASTE-9 The project owner shall submit to the CPM, AO and DTSC for approval the applicant's assessment of whether the HTF contaminated soil is considered hazardous or non-hazardous under state regulations. HTF-contaminated soil that exceeds the hazardous waste levels must be disposed of in accordance with California Health and Safety Code (HSC) Section 25203. HTF contaminated soil that does not exceed the hazardous waste levels may be discharged into the land treatment unit (LTU). For discharges into the LTU, the project owner shall comply with the Waste Discharge Requirements contained in the Soil & Water Resources section of this document.

<u>Verification</u>: The project owner shall document all releases and spills of HTF ~~as described in Condition of Certification WASTE-9~~ ***and report only those that are 42 gallons or more, the CERCLA reportable quantity***, as required in the Soil & Water Resources section of this document. Cleanup and temporary staging of HTF contaminated soils shall be conducted in accordance with the approved Operation Waste Management Plan required in Condition of Certification of WASTE-8. The project owner shall sample HTF-contaminated soil from CERCLA reportable incidents involving 42 gallons or more in accordance with the United States Environmental Protection Agency's (USEPA) current version of "Test Methods for Evaluating Solid Waste" (SW-846). Samples shall be analyzed in accordance with USEPA Method 8015 or other method to be reviewed and approved by DTSC, the CPM and AO.

Within ~~14~~***28*** days of an HTF spill the project owner shall provide the results of the analyses and their assessment of whether the HTF-contaminated soil is considered hazardous or non-hazardous to DTSC and the CPM and AO for review and approval.

If DTSC and the CPM and AO determine the HTF-contaminated soil is considered hazardous it shall be disposed of in accordance with California Health and Safety Code (HSC) Section 25203 and procedures outlined in the approved Operation Waste Management Plan required in Condition of Certification **WASTE-8** and reported to the CPM and AO in accordance with Condition of Certification **WASTE-10**.

If DTSC and the CPM and AO determine the HTF-contaminated soil is considered nonhazardous it shall be retained in the LTU and treated on-site in accordance with the Waste Discharge Requirements contained within in the Soil & Water Resources section of this document.

WORKER SAFETY

Page C.14-28 and 29, Conditions of Certification WORKER SAFETY-7 and 8

PVSI is meeting with the Riverside County Fire Department in the next few weeks to discuss an agreement with the RCFD. PVSI recommends the following modification to this condition:

WORKER SAFETY-8 The project owner shall ***either (1) reach an agreement with the Riverside County Fire Department regarding funding the RCFD for personnel support necessary of the BSPP or*** (2) provide an annual payment of $100,000 to the RCFD for the support of three fire department staff commencing with the date of site mobilization and continuing annually thereafter on the anniversary until the final date of decommissioning.

POWER PLANT RELIABILITY

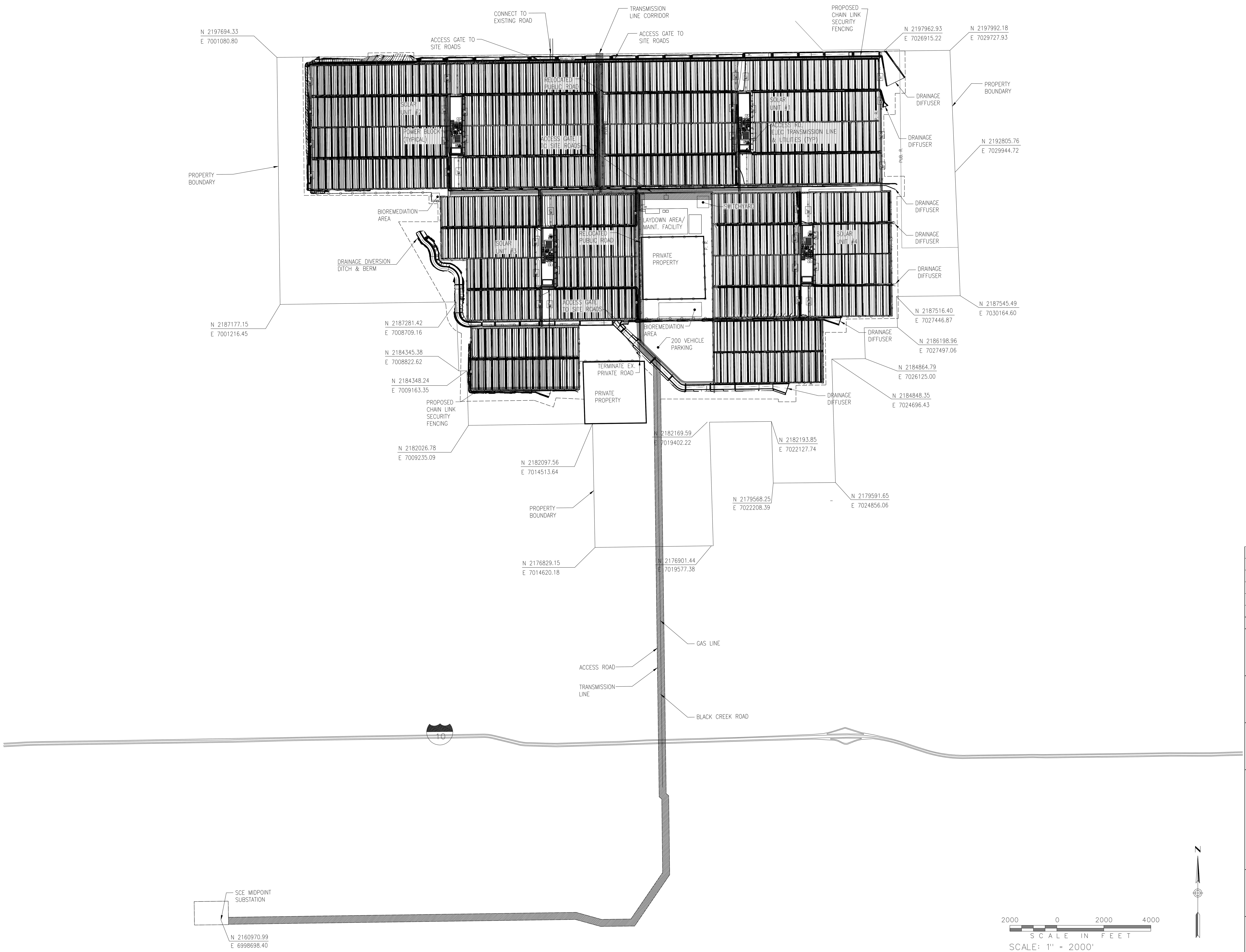
Page 5.3-4, Water Supply Reliability

As discussed in our comments on the Soil & Water analysis, the BSPP has the right to reliably pump groundwater and does not need an entitlement of Colorado River Water from the U.S. Bureau of Reclamation. Staff's misunderstanding regarding such an entitlement is the sole reason it concludes the BSPP has a problem with reliability. Therefore, this section should be revised to conclude that the BSPP will be reliable source of renewable energy.

/original signed/

____

Scott A. Galati
Counsel to Palo Verde Solar I, LLC



- PRELIMINARY -
NOT FOR CONSTRUCTION

REV	DESCRIPTION	DWN	CHK	APP	DATE
F	ADDED NORTHERN/SWITCHYARD TRANSMISSION LINE CORRIDORS	BAS			04-02-10
E	UPDATED DISTURBANCE AREA PER AECOM REQUEST	SMC			03-02-10
D	UPDATED GAS AND TRANSMISSION LINE LOCATION	SMC			02-17-10
C	NEW GAS LINE LOCATION	SMC			02-02-10
B	NEW TRANSMISSION LINE LOCATION	SMC			01-29-10
A	ISSUED FOR REVIEW	SMC			12-31-09

KIEWIT/MAN SOLAR MILLENNIUM

240 MW SOLAR ENERGY CENTER

Kiewit

Kiewit Power
9401 Renner Boulevard
Lenexa, Kansas 66219

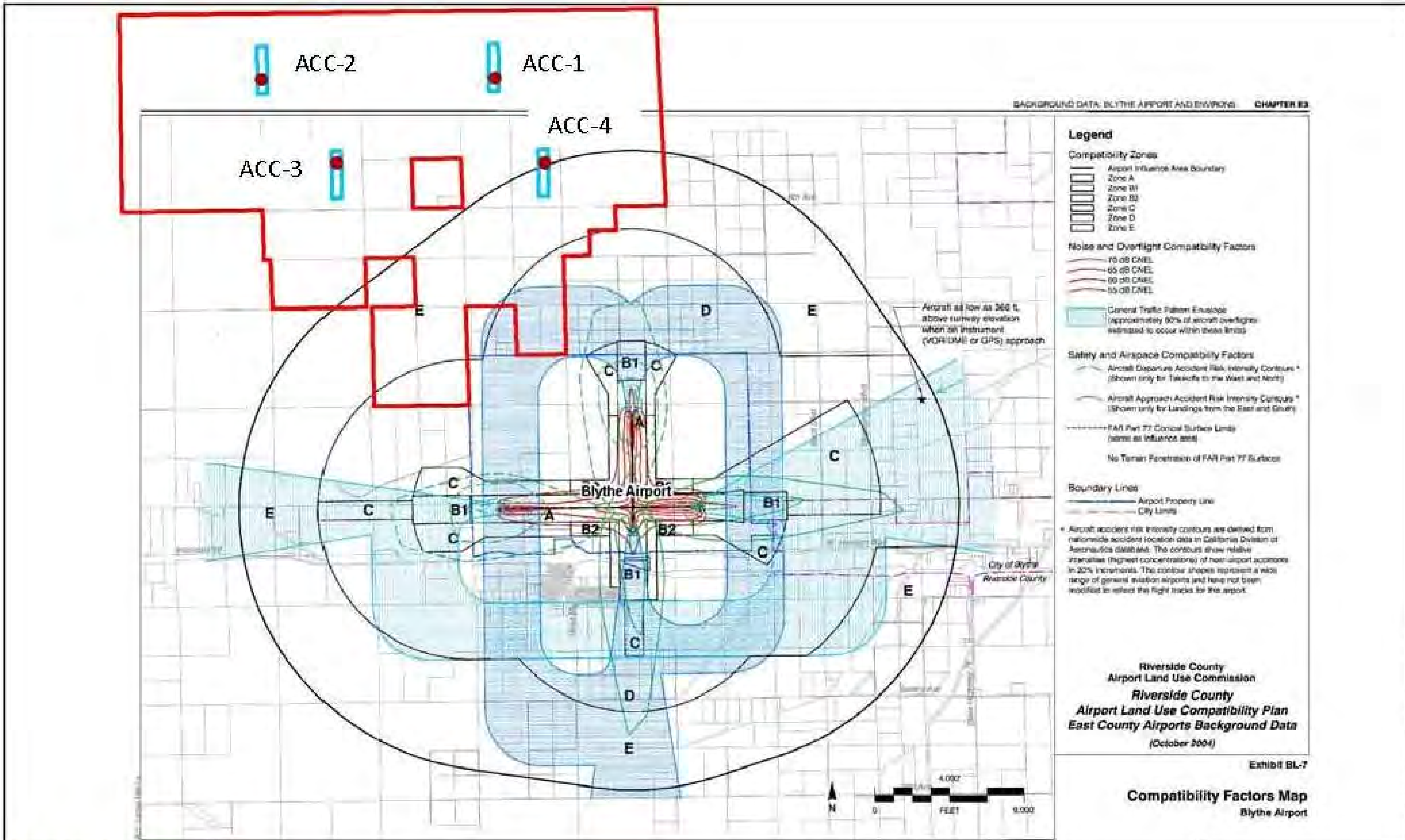
Figure PD-1

SITE PLAN AND BOUNDARY

	by	date
DESIGNED	BAS	12-29-09
DRAWN	SMC	12-30-09
CHECKED		
APPROVED		

DRAWING NUMBER

2008-045-CS-001



Map Location

Legend

- Project Right-of-Way
- Power Blocks
- Air Cooled Condenser

0 1 2 Miles

Blythe Solar Power Project

Figure Trans-1

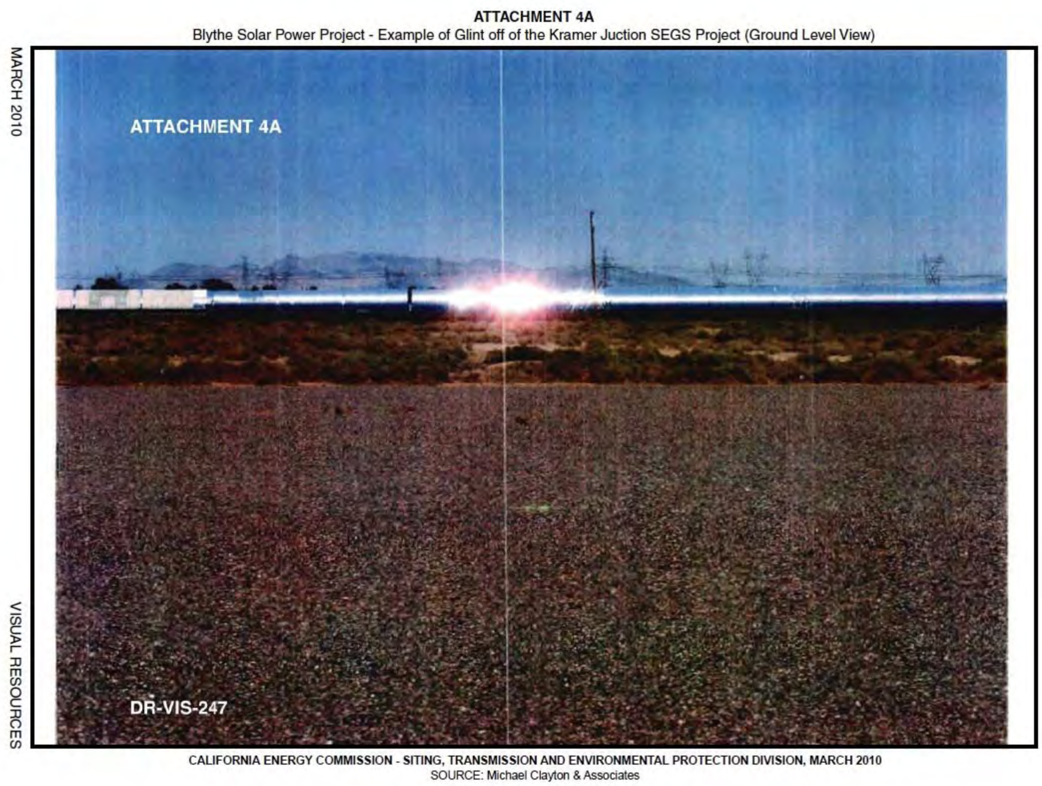
Landing Patterns Blythe Municipal Airport

Palo Verde I, LLC

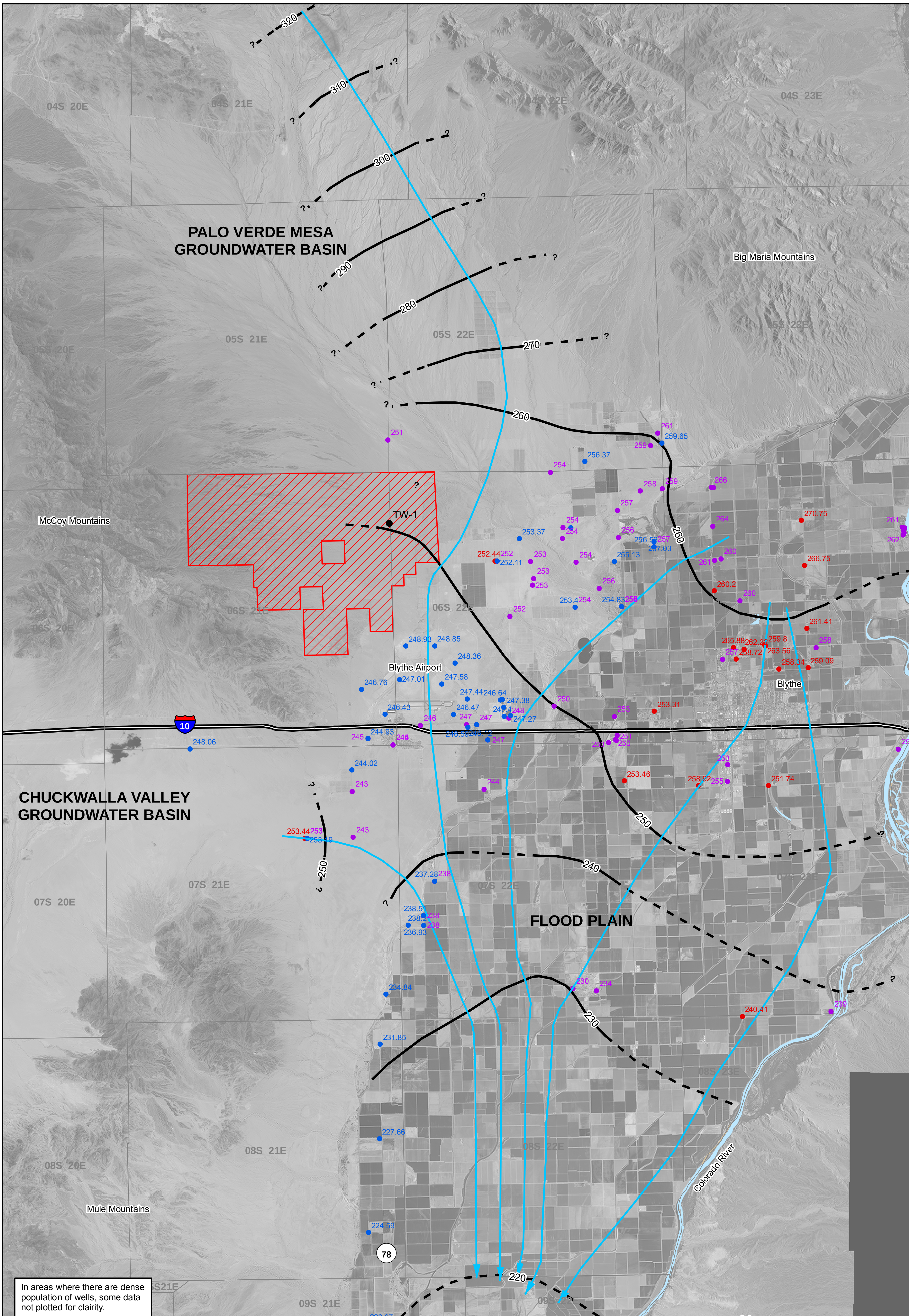
Project: 60139695
Date: February 2010

Figure Vis-1 Comparison of Glare

Photograph by Merlyn Paulson, AECOM of Specular Reflection off of the Kramer Junction SEGS Project (Ground Level View)



Photograph by Michael Clayton & Associates of Glint off of the Kramer Junction SEGS Project (Ground Level View)



Map Location

Legend

- Groundwater Contour Dashed where inferred, Querried where uncertain
- 2000 Groundwater Elevation (feet, msl)
- 2004 Groundwater Elevation (feet, msl)
- 2006 Groundwater Elevation (feet, msl)
- Groundwater Flow Line
- Project Right-of-Way
- Freeway

0 2 4 Miles

Source:

Blythe Solar Power Project

Soil and Water Figure 1 Groundwater Level Contour Map

Palo Verde I, LLC

AECOM

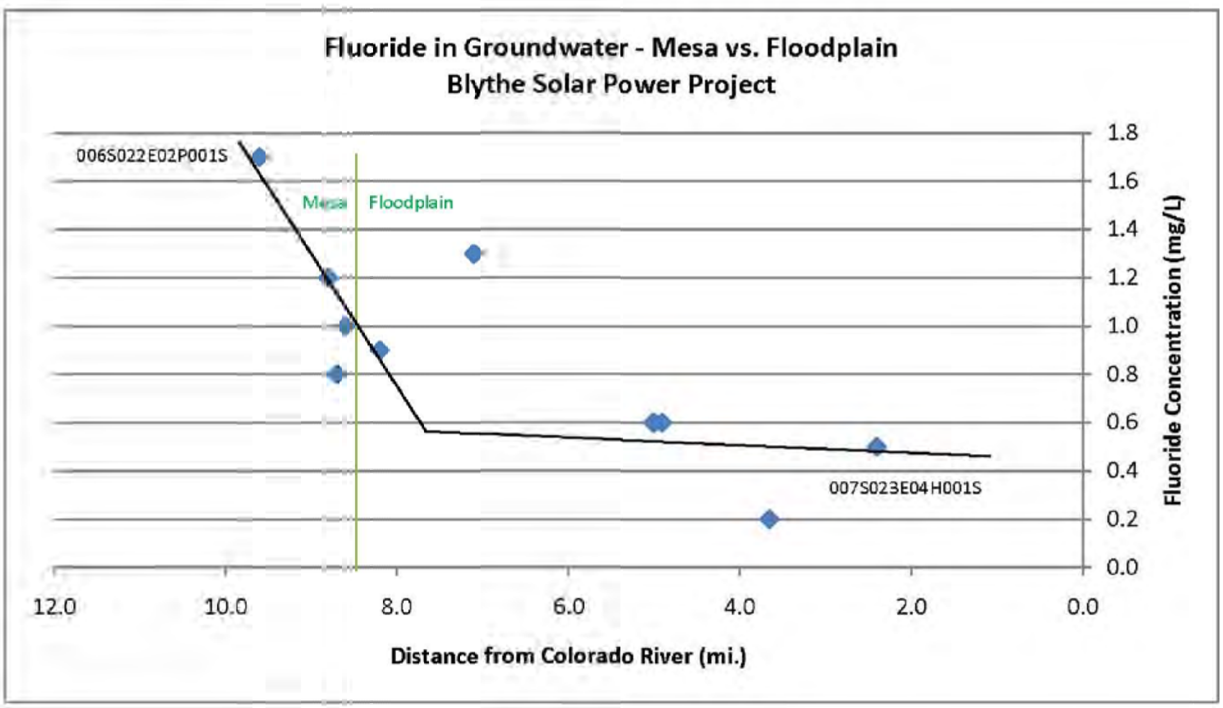
Project: 60139695
Date: April 2010

J:\GIS\Projects\SolarMillinneum\Blythe\mxd\Water Resources\blythe_2000gw-elev.mxd

STATE WELL NAME (USGS)	Distance from Colorado River (mi)	Fluoride, mg/L
007S023E04H001S	2.4	0.5
006S023E32Q001S	3.7	0.2
006S023E29N002S	4.9	0.6
006S023E32D001S	5.0	0.6
006S022E13Q002S	7.1	1.3
006S022E11R002S	8.2	0.9
006S022E11R001S	8.2	0.9
006S022E11H001S	8.6	1.0
006S022E12L002S	8.7	0.8
006S022E01N001S	8.8	1.2
006S022E02P001S	9.6	1.7

Transect Location Map

Northern Transect



Map Location

Blythe Solar Power Project

Soil and Water
Figure 10
Northern Transect
Fluoride in Groundwater -
Mesa vs. Floodplain

AECOM

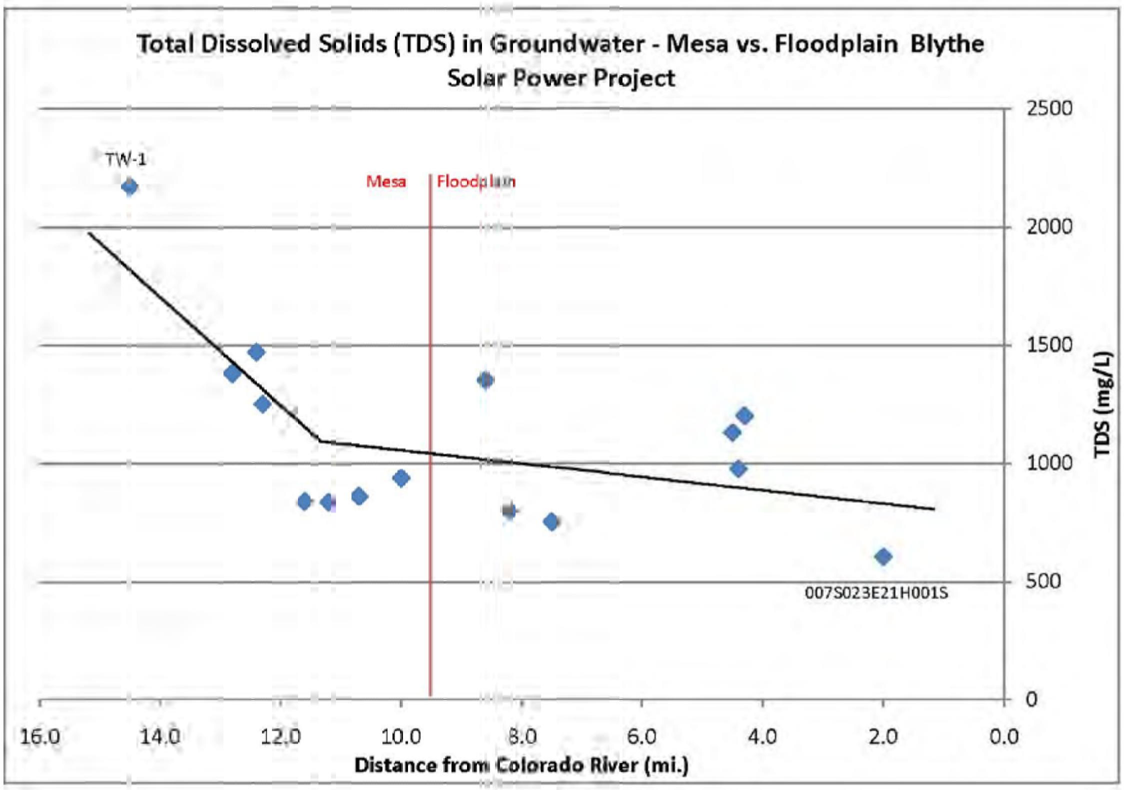
Project: 60139695
Date: April 2010

J:\GIS\Projects\Solar\Millinneum\Blythe\mxd\Water Resources\blythe_GWBasin.mxd

STATE WELL NAME (USGS)	Distance from Colorado River (mi)	Total Dissolved Solids (TDS) mg/L
007S023E21H001S	2.0	604.0
007S023E17D001S	4.3	1200.0
007S023E18A001S	4.4	976.0
007S022E13J001S	4.5	1130.0
006S022E35R002S	7.5	752.0
006S022E35M001S	8.2	797.0
006S022E34L001S	8.6	1350.0
006S022E28G001S	10.0	937.0
006S022E21K001S	10.7	859.0
006S022E21B001S	11.2	835.0
006S022E20A001S	11.6	838.0
006S022E17L001S	12.3	1250.0
006S022E17L002S	12.4	1470.0
006S022E18A001S	12.8	1380.0
TW-1	14.5	2170.0

Transect Location Map

Southern Transect



Map Location

Blythe Solar Power Project

Soil and Water
Figure 11
Southern Transect
TDS in Groundwater -
Mesa vs. Floodplain

AECOM

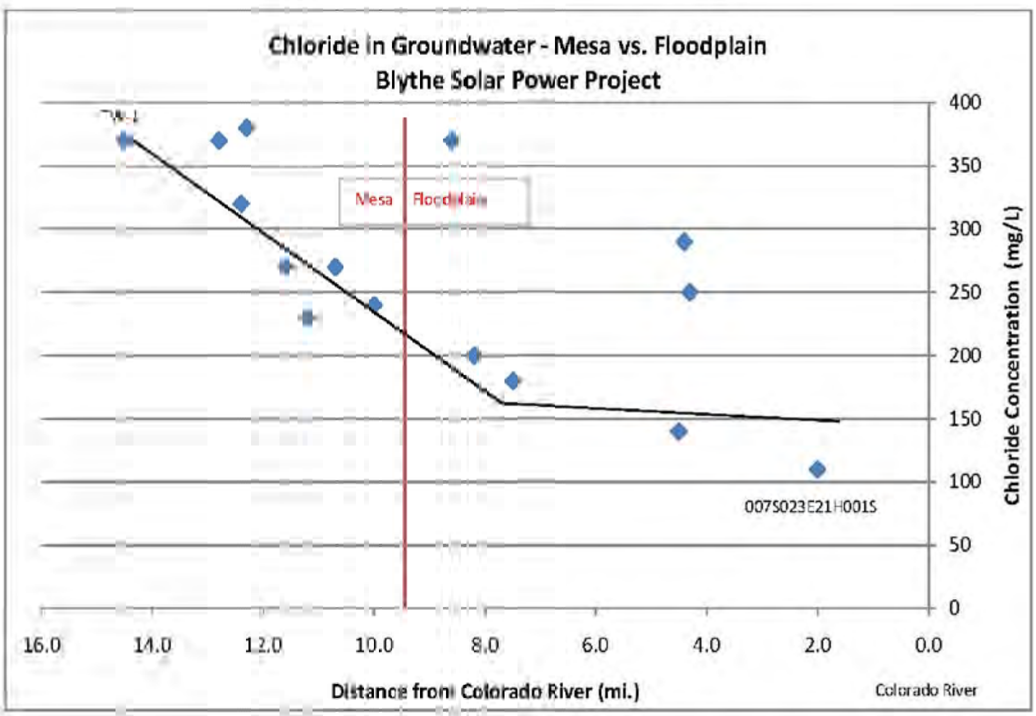
Project: 60139695
Date: April 2010

J:\GIS\Projects\SolarMillinneum\Blythe\mxd\Water Resources\blythe_GWBasin.mxd

STATE WELL NAME (USGS)	Distance from Colorado River (mi)	Chloride, mg/L
007S023E21H001S	2.0	110.0
007S023E17D001S	4.3	250.0
007S023E18A001S	4.4	290.0
007S022E13J001S	4.5	140.0
006S022E35R002S	7.5	180.0
006S022E35M001S	8.2	200.0
006S022E34L001S	8.6	370.0
006S022E28G001S	10.0	240.0
006S022E21K001S	10.7	270.0
006S022E21B001S	11.2	230.0
006S022E20A001S	11.6	270.0
006S022E17L001S	12.3	380.0
006S022E17L002S	12.4	320.0
006S022E18A001S	12.8	370.0
TW-1	14.5	370.0

Transect Location Map

Southern Transect



Map Location

Blythe Solar Power Project

Soil and Water
Figure 12
Southern Transect
Chloride in Groundwater -
Mesa vs. Floodplain

AECOM

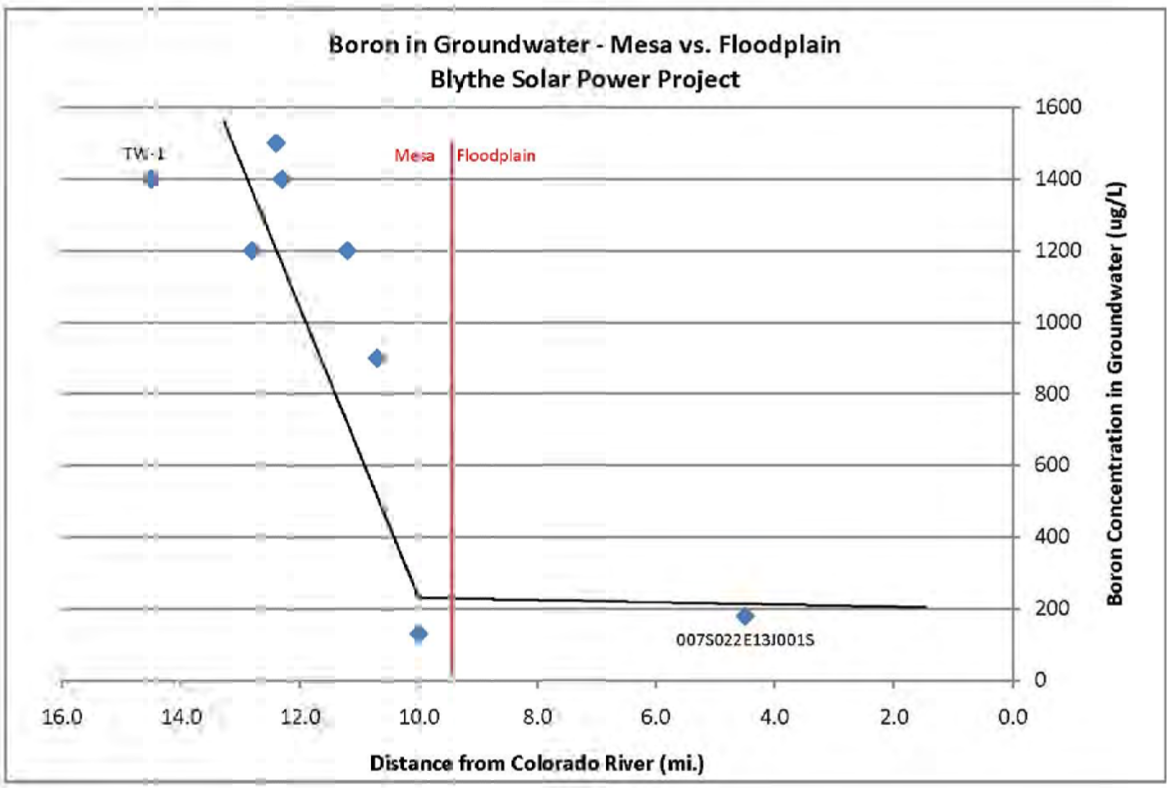
Project: 60139695
Date: April 2010

J:\GIS\Projects\Solar\Millinneum\Blythe\mxd\Water Resources\blythe_GWBasin.mxd

STATE WELL NAME (USGS)	Distance from Colorado River (mi)	Boron (ug/L)
007S023E21H001S	2.0	
007S023E17D001S	4.3	
007S023E18A001S	4.4	
007S022E13J001S	4.5	180.0
006S022E35R002S	7.5	
006S022E35M001S	8.2	
006S022E34L001S	8.6	
006S022E28G001S	10.0	130.0
006S022E21K001S	10.7	900.0
006S022E21B001S	11.2	1200.0
006S022E20A001S	11.6	
006S022E17L001S	12.3	1400.0
006S022E17L002S	12.4	1500.0
006S022E18A001S	12.8	1200.0
TW-1	14.5	1400.0

Transect Location Map

Southern Transect



Map Location

Blythe Solar Power Project

Soil and Water
Figure 13
Southern Transect
Boron in Groundwater -
Mesa vs. Floodplain

AECOM

Project: 60139695
Date: April 2010

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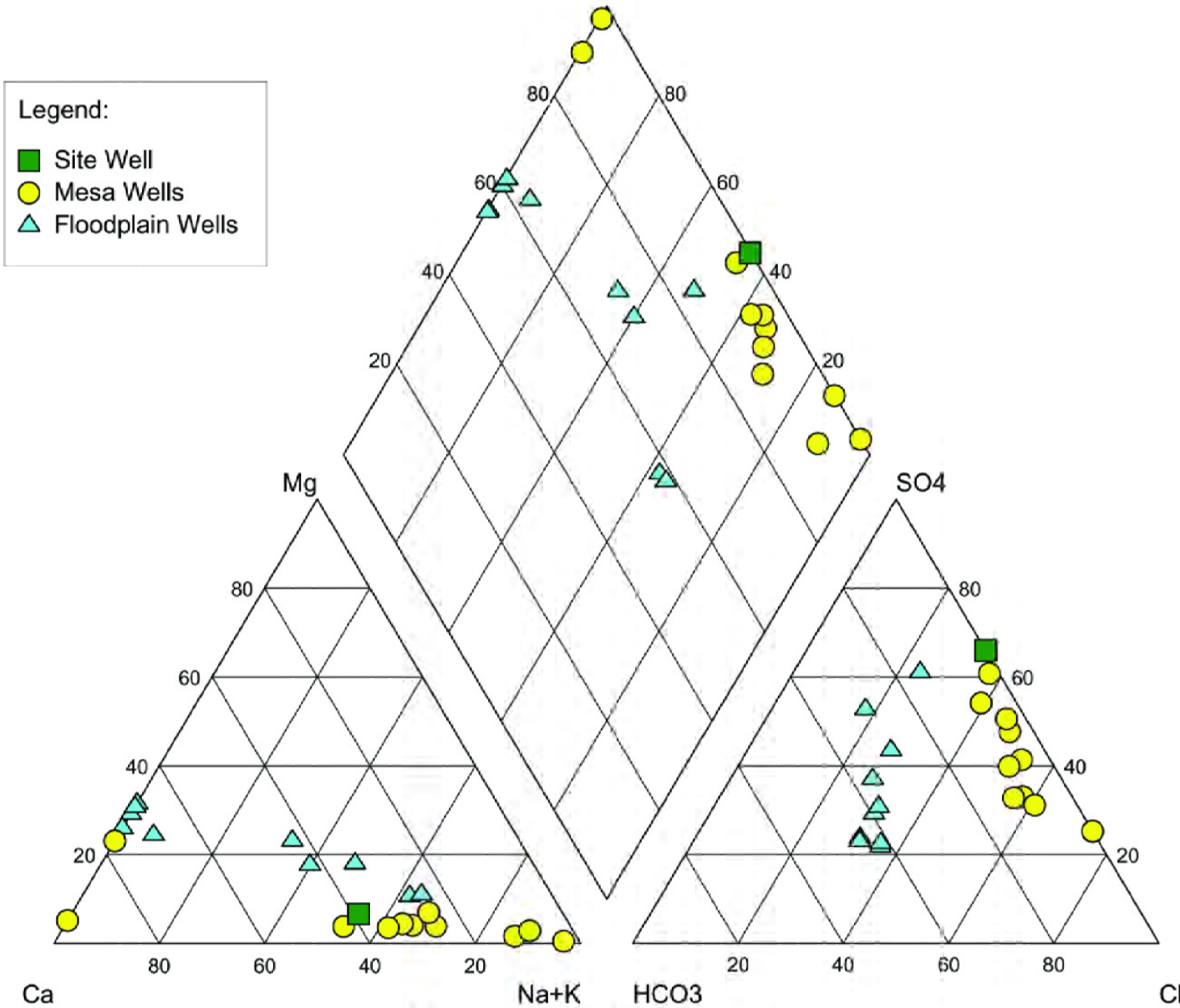

Blythe Water Quality Piper Plot

Blythe Solar Power Project

Soil and Water
Figure 2
Water Type

AECOM

Project: 60139695
Date: April 2010

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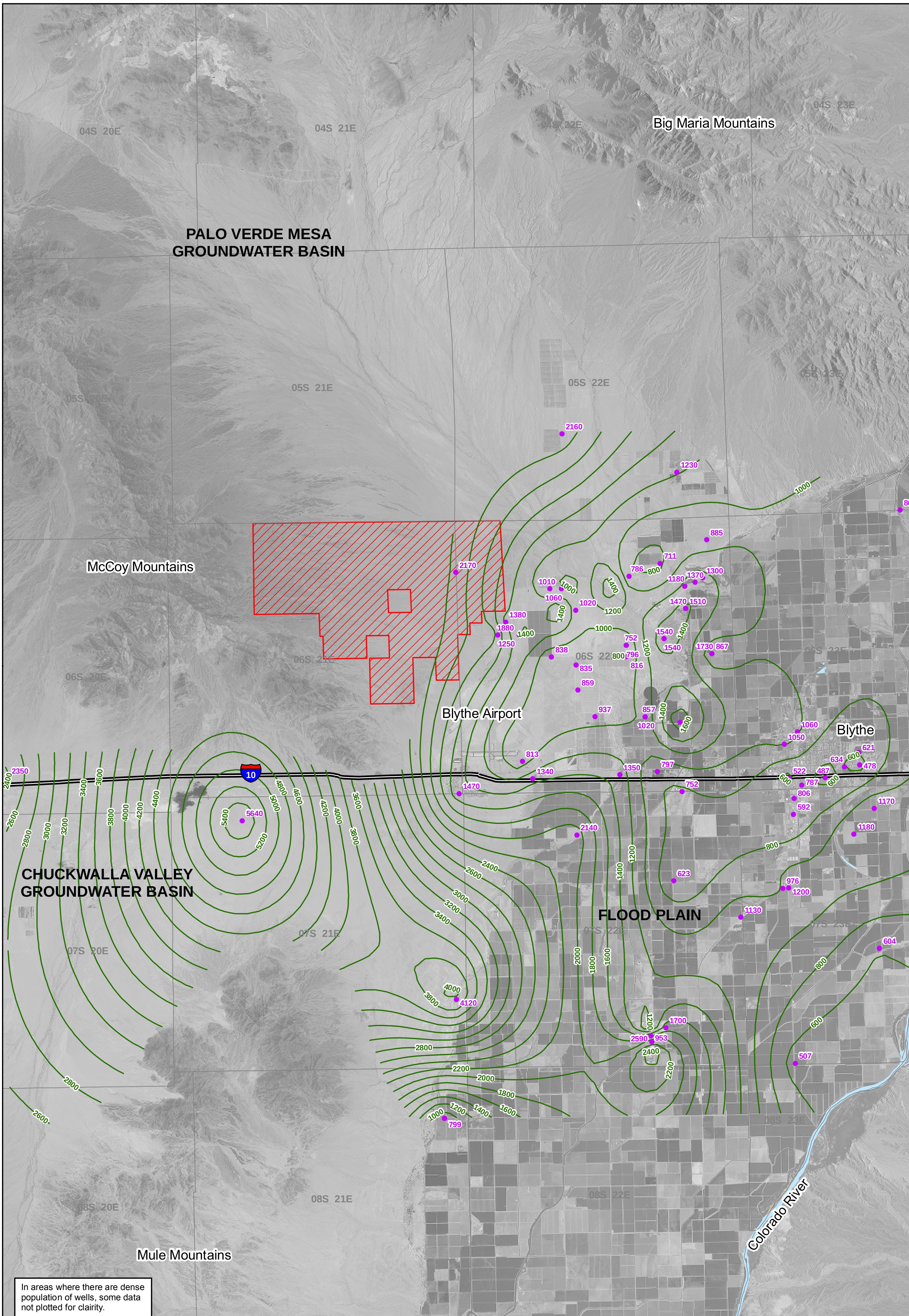


Legend

- TDS in Groundwater
- 4120 Groundwater Well with TDS Concentration
- Freeway
- Highway / Major Road
- Project Right-of-Way

0 2 4 Miles

Blythe Solar Power Project

Soil and Water
Figure 3
TDS in Groundwater
Isoconcentration Map
(Surfer Ver 8)

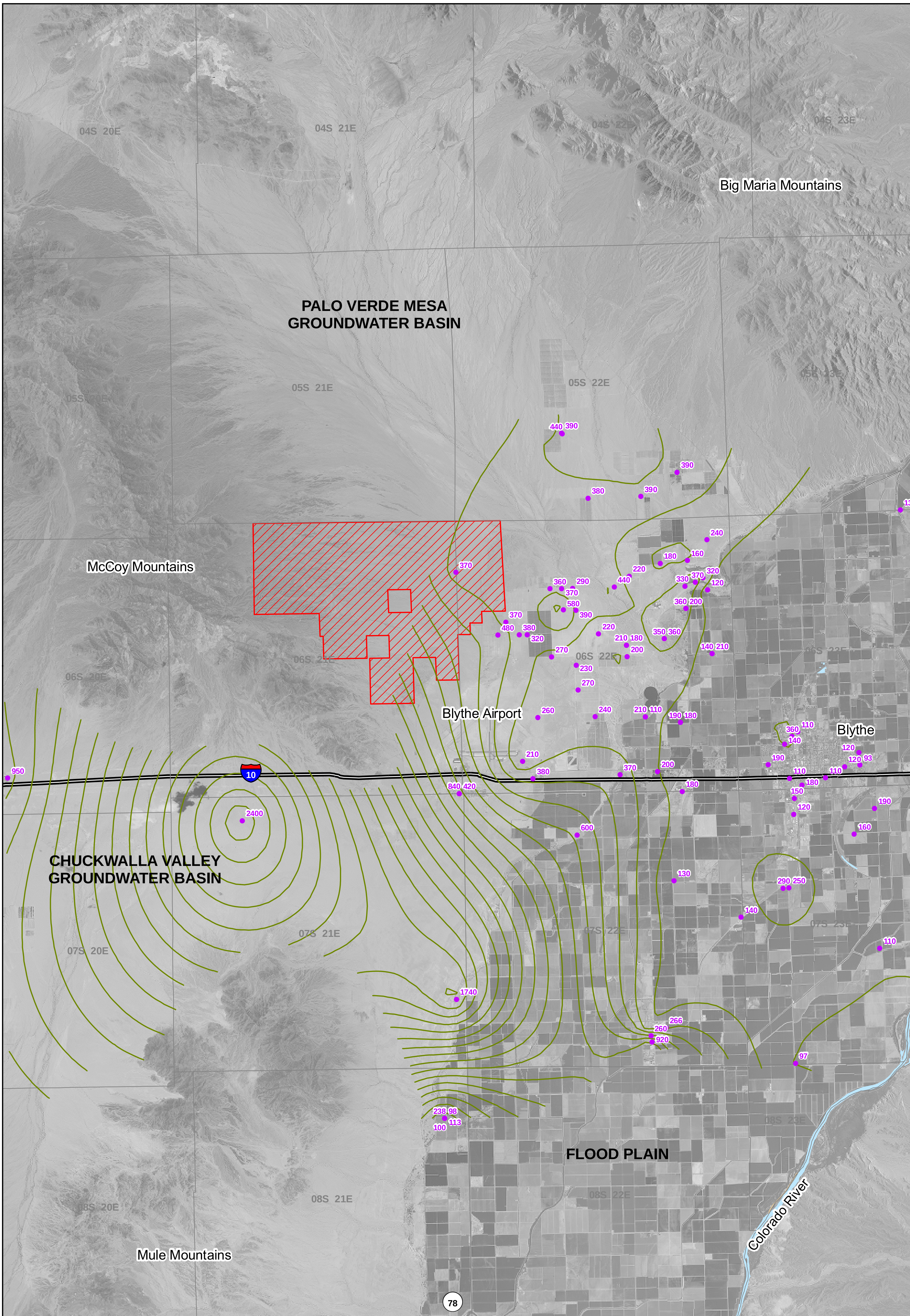
Source:

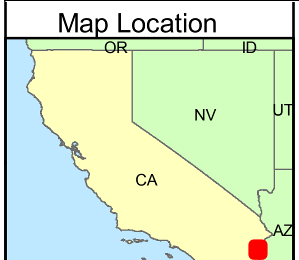
Palo Verde I, LLC

AECOM

Project: 60139695
Date: April 2010

J:\GIS\Projects\SolarMillinneum\Blythe\mxd\Water Resources\blythe_2000gw-elev.mxd





Legend

Chloride in Groundwater

180.00 Groundwater Well with Chloride Concentration

Freeway

Highway / Major Road

Project Right-of-Way

0 2 4 Miles

Blythe Solar Power Project

Soil and Water
Figure 4
Chloride in Groundwater
Isoconcentration Map
(Surfer Ver 8)

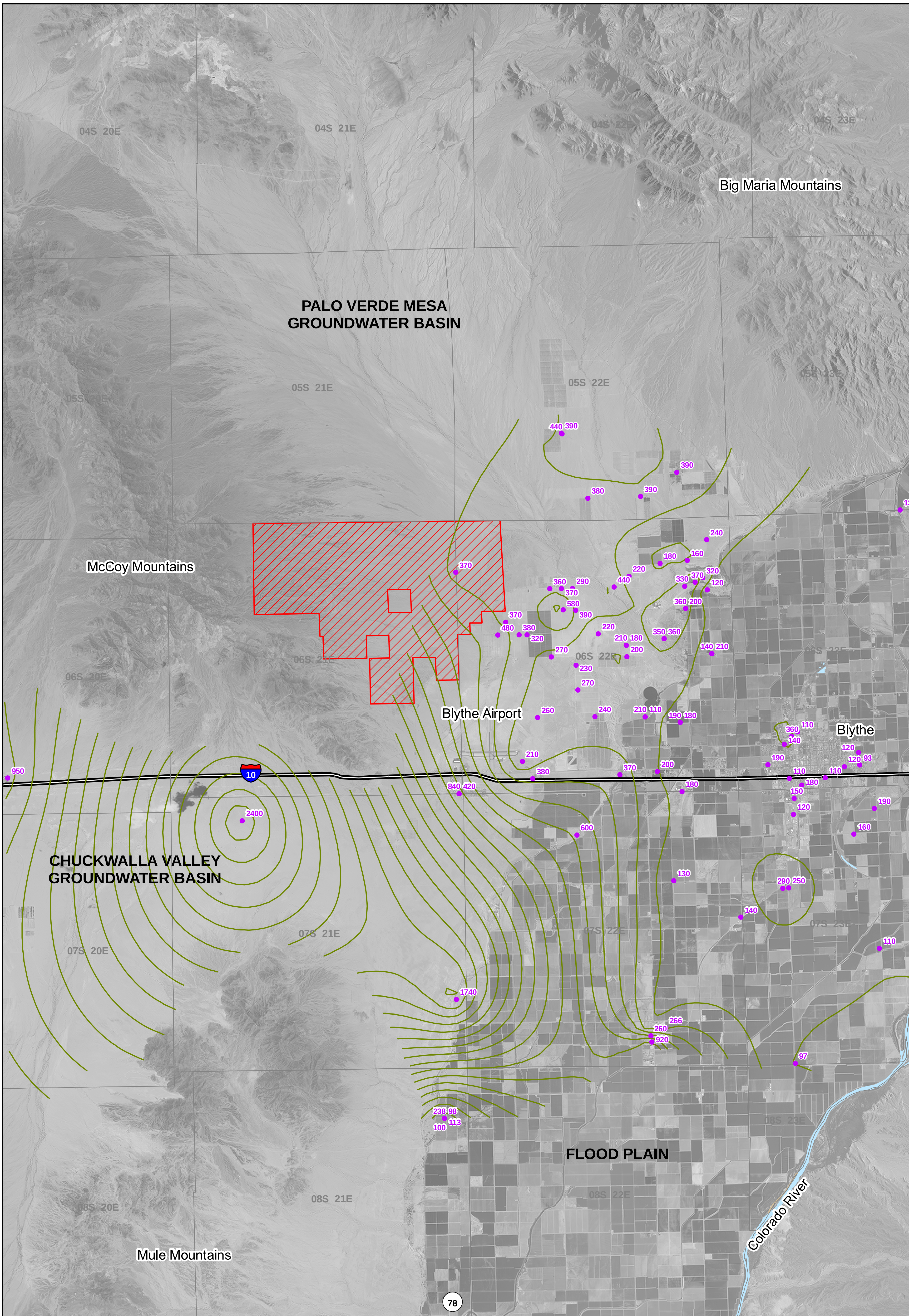
Source:

Palo Verde I, LLC

AECOM

Project: 60139695
Date: April 2010

J:\GIS\Projects\SolarMillennium\Blythe\mxd\Water Resources\blythe_2000gw-elev.mxd



Map Location

Legend

Chloride in Groundwater

180.00 Groundwater Well with Chloride Concentration

Freeway

Highway / Major Road

Project Right-of-Way

0 2 4 Miles

Blythe Solar Power Project

Soil and Water
Figure 4
Chloride in Groundwater Isoconcentration Map
(Surfer Ver 8)

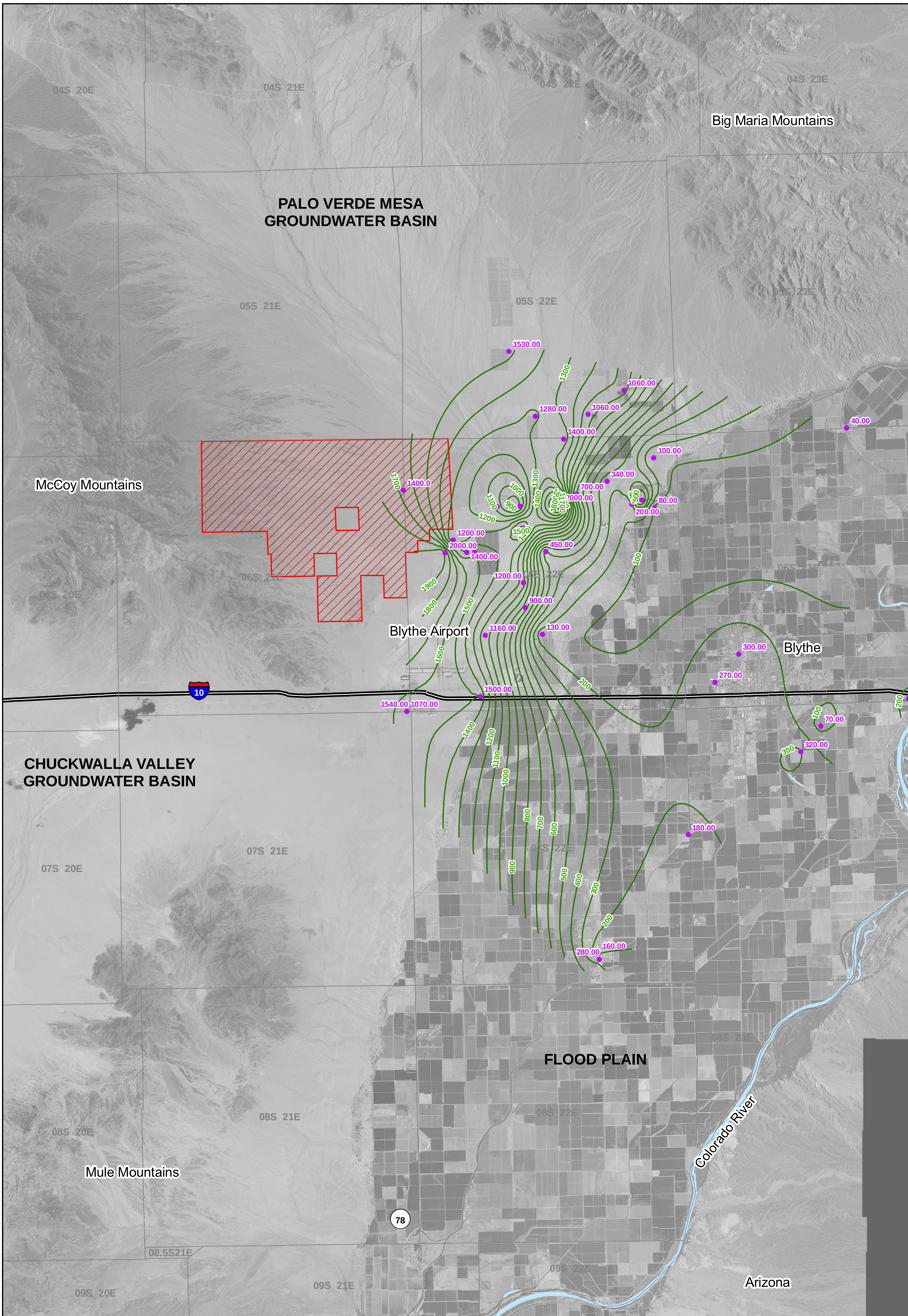
Source:

Palo Verde I, LLC

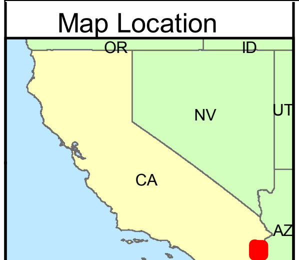
AECOM

Project: 60139695
Date: April 2010

J:\GIS\Projects\SolarMillinneum\Blythe\mxd\Water Resources\blythe_2000gw-elev.mxd



Map Location



Legend

Boron in Groundwater

180.00 Groundwater Well with Boron Concentration

Freeway

Highway / Major Road

Project Right-of-Way

0 2 4 Miles

Blythe Solar Power Project

Soil and Water
Figure 5
Boron in Groundwater Concentration Map
(Surfer Ver 8)

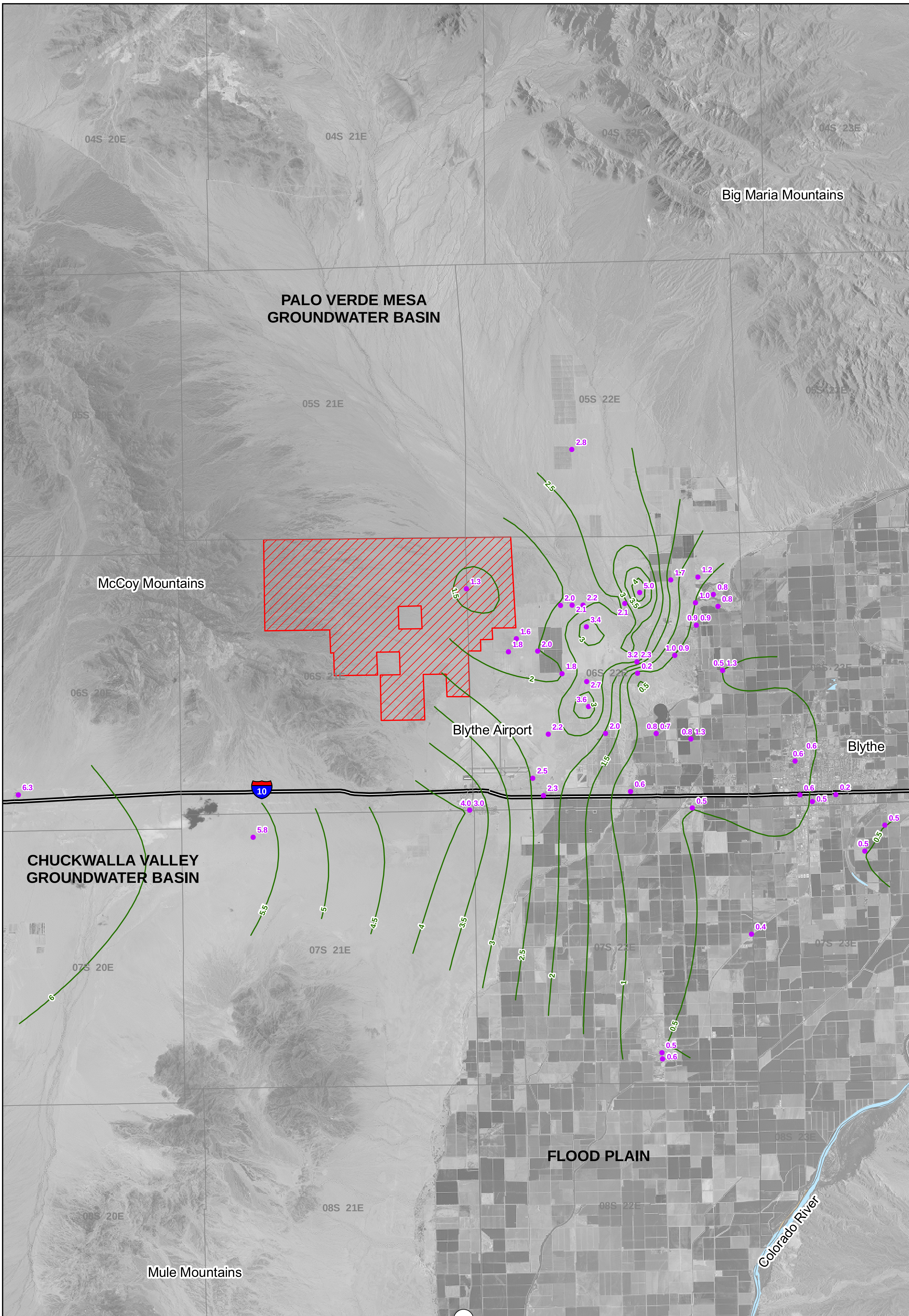
Source:

Palo Verde I, LLC

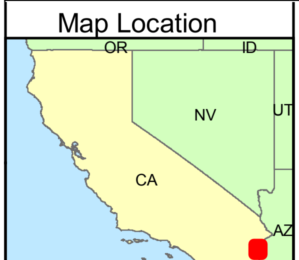
AECOM

Project: 60139695
Date: April 2010

J:\GIS\Projects\SolarMillennium\Blythe\mxd\Water Resources\blythe_2000gw-elev.mxd



Map Location



Legend

- Fluoride in Groundwater
- 180.00 Groundwater Well with Fluoride Concentration
- Freeway
- Highway / Major Road
- Project Right-of-Way

0 2 4 Miles

Source:

Blythe Solar Power Project

Soil and Water
Figure 6
Fluoride in Groundwater
Isoconcentration Map
(Surfer Ver 8)

Palo Verde I, LLC

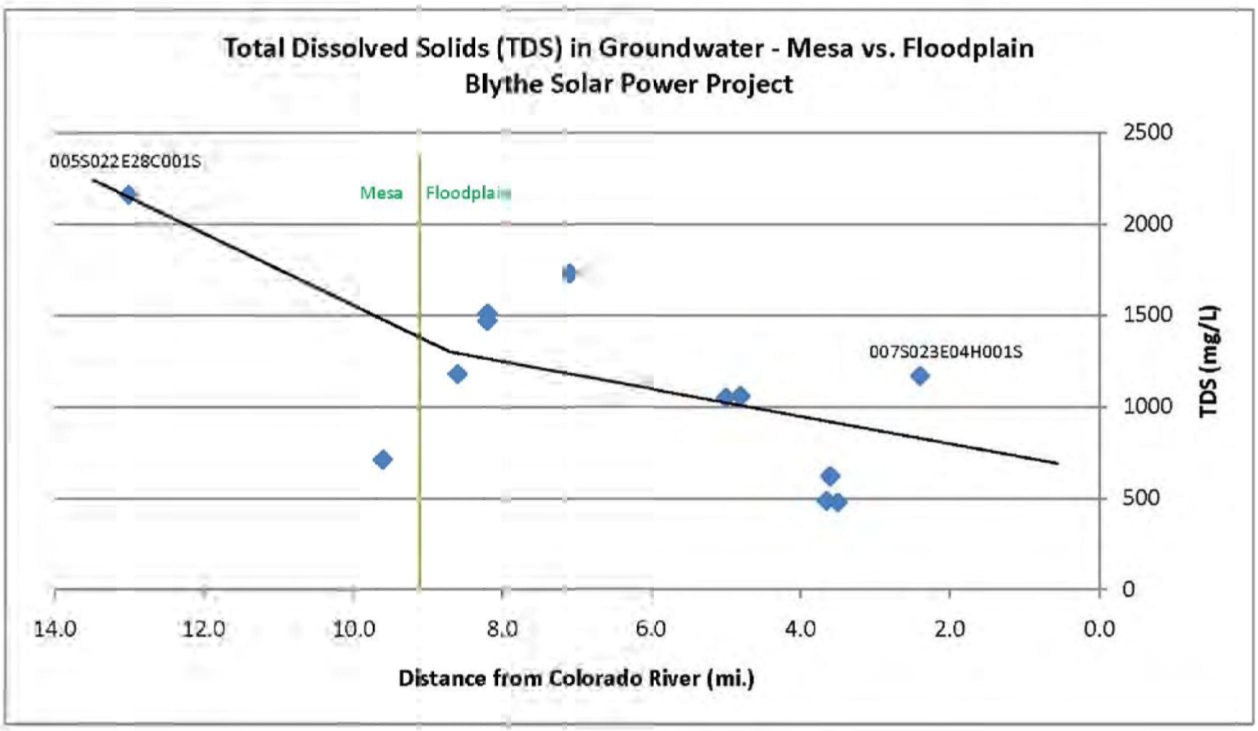
AECOM

Project: 60139695
Date: April 2010

STATE WELL NAME (USGS)	Distance from Colorado River (mi)	Total Dissolved Solids (TDS) mg/L
007S023E04H001S	2.4	1170.0
006S023E33K001S	3.5	478.0
006S023E33G001S	3.6	621.0
006S023E32Q001S	3.7	487.0
006S023E29N001S	4.8	1060.0
006S023E32D001S	5.0	1050.0
006S022E13Q002S	7.1	1730.0
006S022E11R002S	8.2	1510.0
006S022E11R001S	8.2	1470.0
006S022E11H001S	8.6	1180.0
006S022E02P001S	9.6	711.0
005S022E28C001S	13.0	2160.0

Transect Location Map

Northern Transect



Map Location

Blythe Solar Power Project

Soil and Water
Figure 7
Northern Transect
TDS in Groundwater -
Mesa vs. Floodplain

AECOM

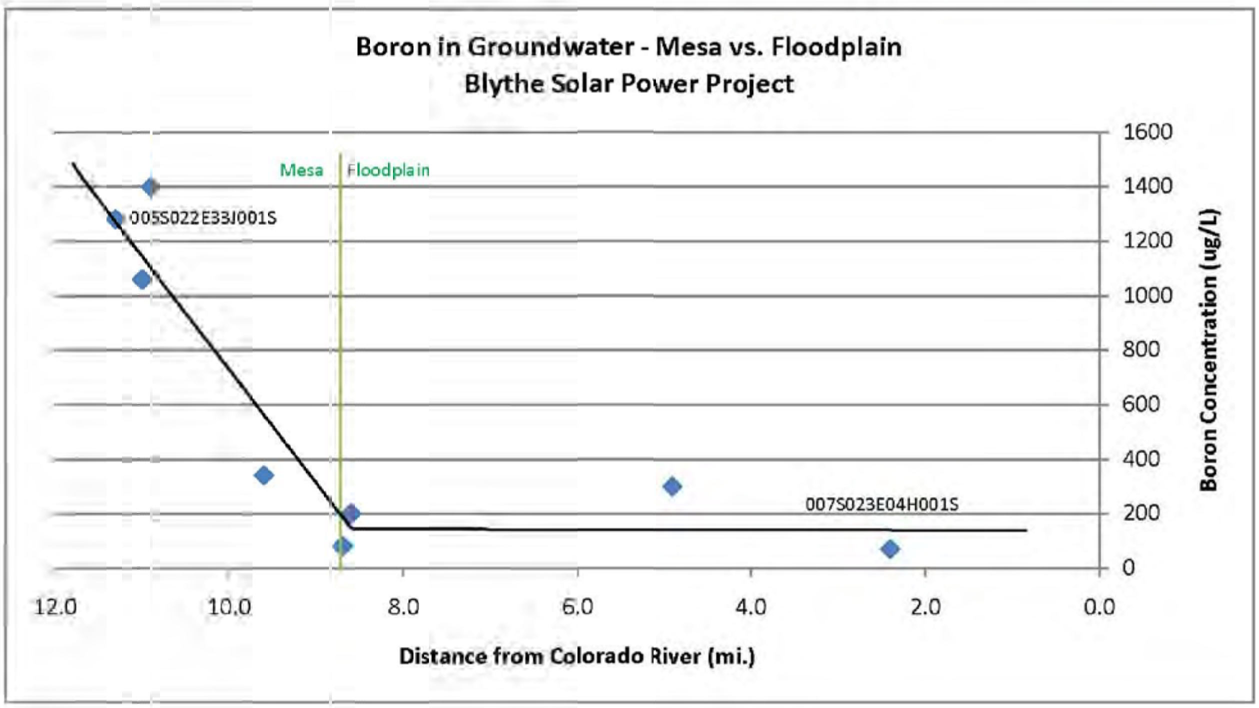
Project: 60139695
Date: April 2010

J:\GIS\Projects\SolarMillinneum\Blythe\mxd\Water Resources\blythe_GWBasin.mxd

STATE WELL NAME (USGS)	Distance from Colorado River (mi)	Boron (ug/L)
007S023E04H001S	2.4	70.00
006S023E29N002S	4.9	300.00
006S022E11H001S	8.6	200.00
006S022E12L002S	8.7	80.00
006S022E02P001S	9.6	340.00
006S022E03B001S	10.9	1400.00
005S022E35M001S	11.0	1060.00
005S022E33J001S	11.3	1280.00

Transect Location Map

Northern Transect



Map Location

Blythe Solar Power Project

Soil and Water
Figure 8
Northern Transect
Boron in Groundwater -
Mesa vs. Floodplain

AECOM

Project: 60139695
Date: April 2010

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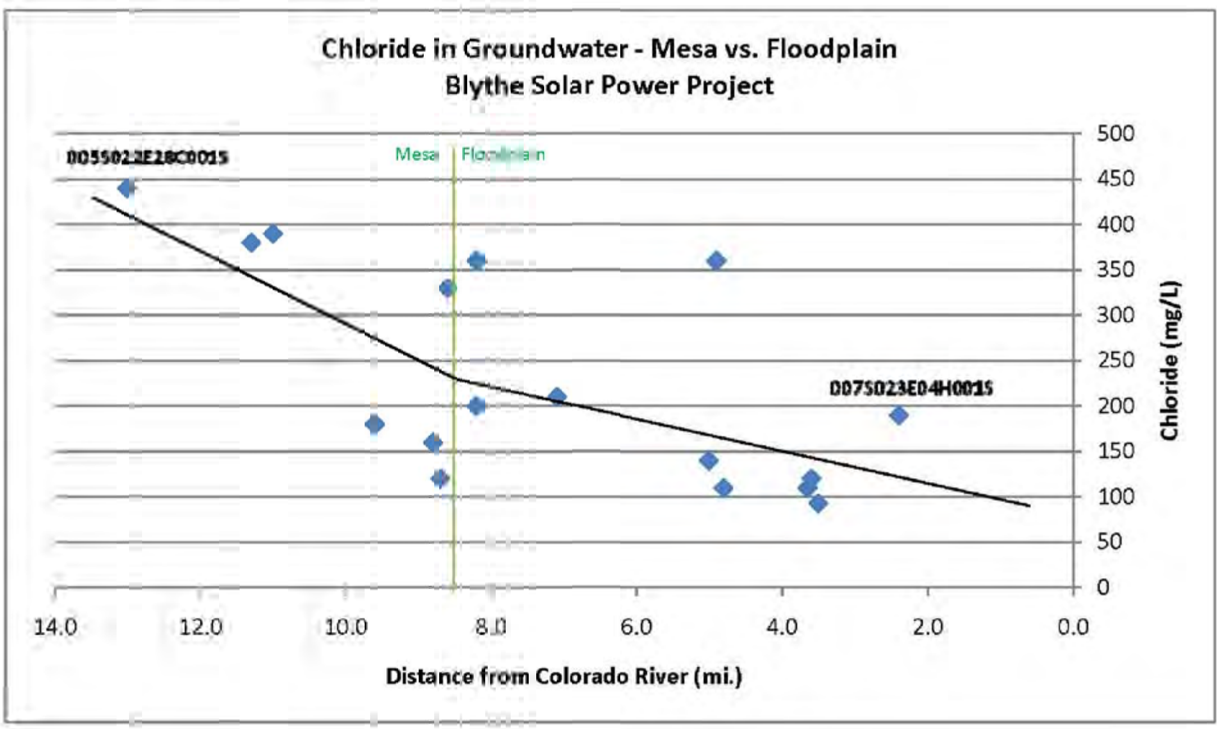
STATE WELL NAME (USGS)	Distance from Colorado River (mi)	Chloride, mg/L
007S023E04H001S	2.4	190.0
006S023E33K001S	3.5	93.0
006S023E33G001S	3.6	120.0
006S023E32Q001S	3.7	110.0
006S023E29N001S	4.8	110.0
006S023E29N002S	4.9	360.0
006S023E32D001S	5.0	140.0
006S022E13Q002S	7.1	210.0
006S022E11R002S	8.2	200.0
006S022E11R001S	8.2	360.0
006S022E11H001S	8.6	330.0
006S022E12L002S	8.7	120.0
006S022E01N001S	8.8	160.0
006S022E02P001S	9.6	180.0
005S022E35M001S	11.0	390.0
005S022E33J001S	11.3	380.0
005S022E28C001S	13.0	440.0

Transect Location Map

Northern Transect



Map Location

Blythe Solar Power Project

Soil and Water
Figure 9
Northern Transect
Chloride in Groundwater - Mesa vs. Floodplain

AECOM

Project: 60139695
Date: April 2010

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ATTACHMENT 1

STAFF ASSESSMENT SECTION B.1
DESCRIPTION OF THE PROPOSED PROJECT:

APPLICANT UPDATE

B.1 DESCRIPTION OF THE PROPOSED PROJECT

Alan Solomon

B.1 PROPOSED PROJECT

B.1.1 INTRODUCTION

On March 16, 2007, the Bureau of Land Management (BLM) received an Application for Transportation and Utility Systems and Facilities on Federal Lands to construct, operate, and maintain the Blythe Solar Power Plant Project (BSPP). On August 24, 2009, the California Energy Commission received an Application For Certification (AFC) from the applicant to construct and operate the BSPP in Riverside County. On October 26, 2009, a Supplement to the AFC was received and evaluated by staff. Subsequently, at the Energy Commission's November 18, 2009 Business Meeting, the AFC was deemed complete, beginning staff's analysis of the proposed project.

The project is proposed to be located in the California inland desert, approximately eight miles west of the city of Blythe and two miles north of the Interstate-10 freeway in Riverside County, California. The applicants are seeking a right-of-way grant for approximately 9,400 acres of land administered by the BLM. The disturbance area for construction~~Construction~~ and operation should be changed from ~~of the project would disturb a total of about~~ 7,030 acres to 7,043 acres and will be revised accordingly to reflect the final transmission line route, temporary construction power line and telecommunication line.

B.1.2 DESCRIPTION

BSPP would consist of four adjacent, independent, and identical units of 250 megawatt (MW) nominal capacity each for a total nominal capacity of 1,000 MW.

The Blythe project would utilize solar parabolic trough technology to generate electricity. With this technology, arrays of parabolic mirrors collect heat energy from the sun and refocus the radiation on a receiver tube located at the focal point of the parabola. A heat transfer fluid (HTF) is heated to high temperature (750°F) as it circulates through the receiver tubes. The heated HTF is then piped through a series of heat exchangers where it releases its stored heat to generate high pressure steam. The steam is then fed to a traditional steam turbine generator where electricity is produced.

Each of the four solar field systems operates under the control of its Field Supervisor Controller (FSC), which is a computer located at each plant's~~in the central~~ control room.

The FSC collects information from each Solar Collector Assembly~~Assemblies~~ (SCA) and issues instructions to the SCAs. Its~~SCA's. Some of its~~ functions include deploying the solar field during the day when weather and facility availability permit, and stowing~~stows~~ it at night and during high winds (in high wind conditions, the solar field must be stowed).

A weather station located in each~~the~~ power block ~~areas~~ provides real-time measurements of weather conditions that affect the solar field operation. Radiation data is used to determine the performance of the solar field.

The FSC communicates all relevant conditions to the plant's distributed control system (DCS). The DCS coordinates and integrates power block, HTF system, and solar field operation.

Individual Components of the Proposed Project

Solar Collector Assemblies - The project's SCAs are oriented north-south to rotate east-west to track the sun as it moves across the sky throughout the day. The SCAs collect heat by means of linear troughs of parabolic reflectors, which focus sunlight onto a straight line of heat collection elements (HCEs) welded along the focus of the parabolic "trough".

Parabolic Trough Collector Loop - Each of the collector loops consist of two adjacent rows of SCAs, each row is about 1,300 feet long. The two rows are connected by a crossover pipe. HTF is heated in the loop and enters the header, which returns hot HTF from all loops to the power block where the power generating equipment is located.

Mirrors - The parabolic mirrors to be used in the Project are low-iron glass mirrors. Typical life spans of the reflective mirrors are expected to be 30 years or more.

Heat Collection Elements - The HCEs of the four solar plants are comprised of a steel tube surrounded by an evacuated glass tube insulator. The steel tube has a coated surface, which enhances its heat transfer properties with a high absorptivity for direct solar radiation, accompanied by low emissivity.

Glass-to-metal seals and metal bellows are incorporated into the HCE to ensure a vacuum-tight enclosure. The enclosure protects the coated surface and reduces heat losses by acting as an insulator.

HTF System - In addition to the HTF piping in the solar field, each of the four HTF systems includes three elements: 1) the HTF heat exchanger~~heater~~, 2) the HTF expansion vessel and overflow vessel, and 3) the HTF ullage system. Rather than~~To eliminate the problem of HTF~~ ~~freezing,~~ a fired HTF heater, a heat exchanger would be installed ~~and used~~ to assist in ensuring ~~ensure~~ system temperature stays above 54°F (12°C). The HTF heat exchanger is an unfired ~~) whenever the~~ unit that utilizes steam from the auxiliary boiler as the heating medium. ~~is offline.~~ ~~A surge tank is~~ The HTF expansion vessel and overflow vessel are required to accommodate the volumetric change that occurs when heating the HTF to the operating temperature.

During plant operation, HTF would degrade into components of high and low boilers (substances with high and low boiling points). The low boilers are removed from the process through the ullage system. HTF is removed from the HTF surge tank and flashed, leaving behind high boilers and residual HTF. The flashed vapors are condensed and collected in the ullage system.

Solar Steam Generator System - At each of the four units, the SSG system transfers the sensible heat from the HTF to the feedwater. The steam generated in the SSG is piped to a Rankine-cycle reheat steam turbine. Heat exchangers are included as part of the SSG system to preheat and boil the condensate, superheat the steam, and reheat the steam.

Steam Turbine Generator - The STG receives steam from the SSG. The steam expands through the STG turbine blades to drive the steam turbine, which then drives the generator, converting mechanical energy to electrical energy. Each of the Project's STGs would be a three-stage casing type with high pressure (HP) intermediate pressure (IP), and low pressure (LP) steam sections. The STG is equipped with the following accessories:

- Steam stop and control valves,
- Gland seal system,
- Lubricating and jacking oil systems,
- Thermal insulation, and
- Control instrumentation.

Operational of the Solar Fields

At each solar field, a DCS containing several automation units controls the HTF and steam loops and all auxiliary plant systems, and determines the appropriate operating sequences for them. It also monitors and records the primary operating parameters and functions as the primary interface for system control.

The DCS communicates with all subsystem controls, including electrical system equipment, steam cycle controllers, variable frequency drives and balance-of-plant system controllers via serial data communication. It receives analog and digital inputs/outputs from all instruments and equipment not served directly by dedicated local controllers. The DCS controls both the steam and HTF cycles directly, operating rotating equipment via relevant electrical panels. It includes a graphical user interface at an operator console in the main control room. Day-to-day, the following operation modes would occur in the HTF system:

- Warm up,
- Solar field mode (heat transfer from solar field to power block),
- Shutdown, and
- Freeze protection.

Warm up

Usually in the morning, the warm up mode brings the HTF flow rate and temperatures up to their steady state operating conditions. It does this by positioning all required valves, starting the required number of HTF main pumps for establishing a minimum flow within the solar field and tracking the solar field collectors into the sun.

At the beginning of warm up at each of the four units, HTF is circulated through a bypass around the power block heat exchangers until the outlet temperature reaches the residual steam temperature in the heat exchangers. HTF is then circulated through the heat exchangers and the bypass is closed. As the HTF temperature at the solar field outlet continues to rise, steam pressure builds up in the heat exchangers until the minimum turbine inlet conditions are reached, upon which the turbine can be started and run up to speed. The turbine is synchronized and loaded according to the design specification until its power output matches the full steady state solar field thermal output.

Solar Field Control Mode

The DCS enters solar field control mode automatically after completing warm-up mode. It regulates the flow by controlling the HTF main pump speeds to maintain the design solar field outlet temperature.

~~Several~~ HTF pumps would generally be operated in parallel, at the speed required to provide the required flow in the field. If the thermal output of the solar field is higher than the design capacity of the steam generation system, collectors within the solar field are de-focused to maintain design operating temperatures.

Shutdown

If the minimal thermal input to the turbine required by the project's operating strategy cannot be met under the prevalent weather conditions, then shutdown is indicated. Operators would track all solar collectors into the stow position, reduce the number of HTF main pumps to a minimum, and stop the HTF flow to the power block heat exchangers.

HTF Freeze Protection System

At each unit, a freeze protection system would be used to prevent freezing of the HTF piping systems when the solar power plant is shut down. Since the HTF freezes at a relatively high temperature (54°F or 12°C), HTF would be routinely circulated at low flow rates throughout the solar field using hot HTF from the storage vessel as a source. This circulation of the warm HTF overnight typically provides adequate freeze protection. During those few of the coldest winter nights where circulation alone is insufficient to provide adequate freeze protection, the auxiliary boiler, which will typically run at 25 percent capacity overnight to provide steam for the STG steam seals, will be utilized at 100 percent capacity to provide steam to an HTF heat exchanger to further heat the HTF.

Major Project Components

The major components and features of the proposed Blythe project include:

- Power Block Unit #1 (northeast);
- Power Block Unit #2 (northwest);

- Power Block Unit #3 (southwest);
- Power Block Unit #4 (southeast);
- Access road from Black Rock Road~~I-10 frontage road~~ to onsite office;
- Office and parking;
- Land Treatment Unit (LTU) for bioremediation/land farming of HTF-contaminated soil;
- Warehouse/maintenance building and laydown area;
- Onsite transmission facilities, including central internal switchyard;
- Dry wash rerouting; and
- Groundwater wells used for water supply.

The four power blocks are identical in design. The~~, except for water treatment systems~~ and ~~water tanks for dust control, which are only found in the power blocks of Unit #1~~ and ~~Unit #3. Otherwise, the~~ descriptions below apply to all four power blocks in all four units.

Major components of each~~the~~ power block include:

- Steam generation heat exchangers;
- HTF overflow and expansion vessels;
- One HTF freeze protection heat exchanger;
- One auxiliary boiler;
- One steam turbine-generator (STG);
- One generator step up transformer (GSU);
- Air Cooled Condenser (ACC);
- One ~~small~~ wet cooling tower for ancillary equipment;
- Water filter system and Clarifier system
- Combination firewater/clarified water tank;
- Reverse osmosis (RO) reject~~concentrate/dust control water storage tank;~~
- ~~Treated~~ water surge tank~~;~~
- Potable Water System
- Demineralized Water System
- Demineralized Water Tank
- High pH Reverse Osmosis (HERO) waste water recovery~~treatment~~ system~~;~~
- Recovered water surge tank
- Evaporation waste stream pond(s)
- Water, natural gas, and HTF pipelines exiting the power block;
- Operations and maintenance buildings; and
- Transmission and telecommunications lines exiting the power block.

Fuel Supply and Use

The auxiliary boiler ~~and HTF heaters~~ for each unit would be fueled by natural gas. The gas for the entire project would be supplied from a new 10-mile (two miles offsite) four-inch~~fourinch~~ diameter pipeline connected to an existing SCG main pipeline south of I-10.

Natural gas delivered to the project site would be delivered via an SCG custody transfer station consisting of filtering equipment, pressure regulating valves, and a fiscal flow meter. Pressure limiting equipment would be provided to ensure the downstream piping would be protected from overpressure. The estimated maximum natural gas usage rate per unit is 35~~70~~ MMBtu/hr~~ when the HTF heater is in use on cold winter nights~~.

Water Supply and Use

The project would be dry cooled. The project's primary water uses include solar mirror washing, feedwater makeup, fire water supply, onsite domestic use, and cooling water for auxiliary equipment~~,~~ heat rejection~~, and dust control~~.

Water Requirements

The average total annual water usage for all four units combined is estimated to be about 600 acre-feet per year (afy), which corresponds to an average flow rate of about 388 gallons per minute (gpm), based on pumping 24 hours per day, 350 days per year.~~).~~ Usage rates during operation would vary during the year and would be higher in the summer months when the peak maximum flow rate could be as much as about 50% higher (about 568 gpm).

Water Source and Quality

The project water needs would be met by use of groundwater pumped from ~~one of two~~ wells on the plant site. Water for domestic uses by project employees would also be provided by onsite groundwater treated to potable water standards.

It is expected that two new water supply wells in each of the power blocks and two additional wells adjacent to the central warehouse ~~of the project site~~ would adequately serve the entire project. A second well would provide redundancy and backup water supply in the event of outages or maintenance of the first well.

Solar Mirror Washing Water

At each solar field, to facilitate dust and contaminant removal, water from the Demineralization~~primary desalination~~ process~~, reverse osmosis (RO) water,~~ would be sprayed on~~used to spray clean~~ the solar collectors for cleaning. The collectors would be cleaned once or twice per week, determined by the reflectivity monitoring program. This mirror washing operation would be done at night and involves a water truck spraying treated water on the mirrors in a drive-by fashion. The applicant expects that the mirrors would be washed weekly in winter and twice weekly from mid spring through mid fall. Because the mirrors are angled down for washing, water does not accumulate on the mirrors; instead, it would fall from the mirrors to the ground and, due to the small volume, is expected to soak in with no appreciable runoff. Any remaining rinse water from the washing operation would be expected to evaporate on the mirror surface. The treated water production facilities would be sized to accommodate the solar mirror washing demand of about 230 afy.

Cooling Systems

Each of the four power plant units includes two cooling systems: 1) the air-cooled steam cycle heat rejection system and, 2) the closed cooling water system for ancillary equipment cooling:

Steam Cycle Heat Rejection System

The cooling system for heat rejection from the steam cycle consists of a forced draft air-cooled condenser, or dry cooling system. At each power block, the dry cooling system receives exhaust steam from the LP section of the STG and condenses it to liquid for return to the SSG.

Auxiliary Cooling Water System

The auxiliary cooling water systems uses a~~use small~~ wet cooling tower~~towers~~ for cooling plant equipment, including the STG lubrication oil cooler, the STG generator cooler, steam cycle sample coolers, large pumps, etc. The water is warmed by~~picks up heat from~~ the various equipment items being cooled and rejects the heat to the cooling tower. This auxiliary cooling system would allow critical equipment such as the generator and HTF pumps to operate at their design ratings during hot summer months when the project's power output is most valuable. An average of 146,000 gallons of water per day (160 afy) would be consumed by the auxiliary cooling water system; the maximum rate of consumption is 223,000 gallons per day in summer.

Waste Generation and Management

Project wastes would be comprised of non-hazardous wastes including solids and liquids and lesser amounts of hazardous wastes and universal wastes. The non-hazardous~~nonhazardous~~ solid waste primarily would consist of construction and office wastes, as well as liquid and solid wastes from the water treatment system. The non-hazardous solid wastes would be trucked to the nearest Class II or III landfill. Non-hazardous liquid wastes would consist primarily of domestic sewage and waste water streams such as: RO system reject water boiler blowdown, and auxiliary cooling tower blowdown. A septic tank and leach field system would be installed to manage domestic sewage. All other waste streams will be either recycled or sent to the evaporation pond. ~~wastes would consist primarily of domestic sewage, and reusable water streams such as RO system reject water, boiler blowdown, and auxiliary cooling tower blowdown. A septic tank and leach field system would be installed to manage domestic sewage.~~

Wastewater

The Blythe project would produce four~~two~~ primary wastewater streams:

- Non-reusable sanitary wastewater produced from administrative centers and operator stations~~.~~
- Non-reusable ~~Reusable streams including: blowdown from the~~ cooling tower blowdown
- Partially recyclable ~~for the ancillary equipment heat rejection system, RO~~

~~reject water, and~~ boiler blowdown (to be used as cooling tower makeup)

- Reusable RO and demineralized reject water that will be sent to a HERO type system, or concentrated to minimize waste streams to the evaporation ponds.

Sanitary wastewater production is based on ~~would consist of~~ domestic water use. Maximum domestic water use is expected to be less than 332,000 gallons per month (11,000 gallons per day). It is anticipated that the wastewater would be consistent with domestic sanitary wastewater and would have biochemical oxygen demand and total suspended solids in the range of 150 to 250 mg/L.

Wastewater Treatment

Sanitary wastes would be collected for treatment in septic tanks and disposed via leach fields located at the four power blocks as well as at the administration area and warehouse area. Smaller septic systems would be provided for the control room buildings to receive sanitary wastes at those locations. Based on the current estimate of 11,000 gallons of sanitary wastewater production per day for the entire site, a total leach field area of approximately 22,000 square feet would be required spread out among several locations.

In a typical wet cooled power plant, water is cycled in the cooling tower until the concentration of chemical constituents rises to levels where it becomes unusable (e.g., typically five to ten cycles of concentration) and is then blown down as a waste stream. Dilute waste streams such as boiler blow downs and some RO concentrate may be fed to the cooling tower and further concentrated; this design practice helps reduce the total waste water flow that then must be sent to an evaporation pond or other treatment system. While dry cooling the power cycle significantly reduces the overall water usage of a plant, it eliminates the cooling tower recycle option that helps minimize waste flows from the remaining water processes. The auxiliary wet cooling tower is too small to concentrate the remaining water flows.

The three plant waste water streams, cooling tower blowdown, boiler blow down, and RO/ Demineralizer water rejects will be recycled as much as possible to the High pH Reverse Osmosis (HERO) system for recovery. The HERO system will recover 70% or more (depending on water quality) of this waste stream and will significantly limit the size of the required evaporation pond(s). Some waste water sources such as cooling tower blowdown or boiler blowdown in certain cases may not be recoverable in the HERO system and would be sent directly to the evaporation pond(s).

The waste water treatment system will require two 4 acre evaporation ponds per power block. Two ponds were selected for reliability. The plant will operate on one pond for approximately 24 months, and then switch the second pond. Approximately 18 months is required for one pond to evaporate and be ready for use again. If a pond requires maintenance or solids removal, the plant can still operate with the other pond. The evaporation ponds will be double-lined and covered with narrow-mesh netting to prevent access by ravens and migratory birds in accordance with applicable regulations.

~~fields located at the four power blocks as well as at the administration area and warehouse area. Smaller septic systems would be provided for the control room buildings to receive sanitary wastes at those locations. Based on the current estimate of 11,000 gallons of sanitary wastewater production per day for the entire site, a total leach field area of approximately 22,000 square feet would be required spread out among several locations.~~

Construction Wastewater
Sanitary wastes produced during construction would be held in chemical toilets and transported offsite for disposal by a commercial chemical toilet service. Any other hazardous wastewater produced during construction such as equipment rinse water would be collected by the construction contractor in Baker tanks and transported off site for disposal in a manner consistent with applicable regulatory requirements.

On-Site Land Treatment Unit
The four solar fields to be installed at the project would require ~~share two~~ LTUs to bioremediate or land farm soil contaminated from releases of HTF. Each LTU would be designed in accordance with Colorado River Basin Regional Water Quality Control Board (RWQCB) requirements and is expected to comprise an area of about 4 ~~360,000 square feet (8.3~~ acres per solar plant, or 16 acres total.~~).~~ The bioremediation facility would utilize indigenous bacteria to metabolize hydrocarbons contained in non-hazardous HTF contaminated soil. A combination of nutrients, water, and aeration facilitates the bacterial activity where microbes restore contaminated soil within two to four months. The California Department of Toxic Substances Control (DTSC) has determined for a similar thermal solar power plant that soil contaminated with up to 10,000 mg/kg of HTF is classified as a non-hazardous waste. However, the DTSC has further indicated that site-specific data would be required to provide a classification of the waste. Soil contaminated with HTF levels of between 100 and 1,000 mg/kg would be land farmed at the LTU, meaning that the soil would be aerated but no nutrients would be added.

Other Non-Hazardous Solid Waste
Non-hazardous solid wastes may be generated by construction, operation, and maintenance of the project which are typical of power generation facilities. These wastes may include scrap metal, plastic, insulation material, glass, paper, empty containers, and other solid wastes. Disposal of these wastes would be accomplished by contracted solid refuse collection and recycling services.

Hazardous Solid and Liquid Waste
Limited hazardous wastes would be generated during construction and operation. During construction, these wastes may include substances such as paint and paint-related wastes (e.g., primer, paint thinner, and other solvents), equipment cleaning wastes and spent batteries. During project operation, these wastes may include used oils, hydraulic fluids, greases, filters, spent cleaning solutions, spent batteries, and spent activated carbon. Both construction and operation-phase hazardous waste would

be recycled and reused to the maximum extent possible. All wastes that cannot be recycled and any waste remaining after recycling would be disposed of in accordance with all applicable laws, ordinances, regulations and standards (LORS).

Hazardous Materials Management
There would be a variety of hazardous materials used and stored during construction and operation of the project. Hazardous materials that would be used during construction include gasoline, diesel fuel, oil, lubricants, and small quantities of solvents and paints. All hazardous materials used during construction and operation would be stored onsite in storage tanks/vessels/containers that are specifically designed for the characteristics of the materials to be stored; as appropriate, the storage facilities would include the needed secondary containment in case of tank/vessel failure. Aboveground carbon steel tanks (300 gallons) also would be used to store diesel fuel at each power block. Secondary containment would be provided for these tanks.

Fire Protection
Fire protection systems are provided to limit personnel injury, property loss, and project downtime resulting from a fire. The systems include a fire protection water system, foam generators, carbon dioxide fire protection systems, and portable fire extinguishers. The location of the project is such that it would fall under the jurisdiction of the Riverside County Fire Department.

Firewater would be supplied from the one million-gallon clarified~~treated~~ water ~~(permeate)~~ storage tanks located at each of the four power blocks on the site. One electric and one diesel-fueled backup firewater pump, each with a capacity of 5,000 gpm, would deliver water to the fire protection piping network.

The piping network would be configured in a loop so that a piping failure can be quickly isolated with shutoff valves without interrupting water supply to other areas in the loop. Fire hydrants would be placed at intervals throughout the project site that would be supplied with water from the supply loop. The water supply loop would also supply firewater to a sprinkler deluge system at each unit transformer, HTF expansion tank and circulating pump area and sprinkler systems at the steam turbine generator and in the administration building. Fire protection for each solar field would be provided by zoned isolation of the HTF lines in the event of a rupture that results in a fire.

Telecommunications and Telemetry
The project would have telecommunications service from Frontier Communications, ~~providers who serve~~ the telecommunications service provider for Blythe~~ area~~. Voice and data communications would be provided~~supported~~ by a new twisted pair telecommunications cable. The routing for this cable will follow the routing of the redundant telecommunications ~~fiber optic~~ line from the project~~which is anticipated~~ to the Colorado River Substation. The routing for both of these lines will be adjacent to Black Rock Road~~follow,~~ and the site access road. Wireless~~be within, the new transmission line alignment.~~

~~This would be augmented with wireless~~ telecom equipment will be used~~, particularly~~ to support communication with staff dispersed throughout the project site. The ~~Regarding telemetry, the~~ project would utilize electronic telemetry systems to control equipment and facilities operations over the site.

Lighting System
The project's lighting system would provide operations and maintenance personnel with illumination in normal and emergency conditions. AC lighting would be the primary form of illumination, but DC lighting would be included for activities or emergency egress required during an outage of the plant's AC system.

HTF Leak Detection
Leak detection of HTF would be accomplished in various ways. Visual inspection throughout the solar field on a daily basis would detect ~~small~~ leaks occurring at ball joints or other connections. Additionally~~; additionally~~, the configuration of the looped system allows different sections of the loops to be isolated. Isolation valves will be installed such that each HTF loop sections can be contained in the unlikely event of a major rupture in the HTF piping.

Detection of large leaks is being proposed by using remote pressure sensing equipment and remotely- actuated~~remote operating~~ valves to allow for isolation of large sections~~areas~~ of the large-bore header piping~~loops~~ in the solar field.

Water Storage Tanks
In each power block there~~There~~ would be two major~~six~~ covered water tanks: one 1,000~~on the site: two 300~~,000-gallon Service/Fire Water~~RO~~ ~~concentrate/dust control~~ storage tank and one 120,000-gallon Demineralized Water storage tank. A much smaller RO Reject water tank would also be provided. Several other small water system surge tanks will also be installed~~located~~ in between various steps ~~Unit #1 and Unit #3 and four one million-gallon treated water storage tanks, one~~ in the water treatment process~~each power block~~. Water storage tanks would be vertical, cylindrical, field-erected steel tanks supported on foundations consisting of either a reinforced concrete mat or a reinforced concrete ring wall with an interior bearing layer of compacted sand supporting the tank bottom.

Roads, Fencing, and Security
Access to the Blythe project site would be via a new ~~the~~ public road heading north from the frontage road. This road would be accessed from an improved section of Black Rock Road along I-10, from the plant access road to the Airport/Mesa Drive exit. ~~frontage road, Black Rock Road, along I-10, accessed from the Airport/Mesa Drive exit. Improvements to some segments of the public road would be required.~~
Only a small portion of the overall project site would be paved, primarily the site access road, the service roads to the power blocks, and portions of the power blocks (paved parking lot and roads encircling the STG and SSG areas). The remaining portions of each power block would be gravel surfaced. In total, each power block area would be approximately 18.4 acres each, with approximately six acres of paved area. The

solar fields would remain unpaved and without a gravel surface in order to prevent rock damage from mirror wash vehicle traffic; an approved dust suppression coating would be used on the dirt roadways within and around the solar fields. Roads and parking areas located within the power block areas and adjacent to the administration building and warehouses would be paved with asphalt.

The project solar fields and support facilities' perimeter would be secured with a combination of chain link and wind fencing. Chainlink metal fabric security fencing consists of eight-foot tall fencing with one-foot barbed wire or razor wire on top along the north and south sides of the facilities. Thirty-foot tall wind fencing, comprised of A-frames~~Aframes~~ and wire mesh, would be installed along the east and west sides of each solar field. Desert Tortoise exclusion fencing would be included. Controlled access gates would be located at the site entrance. As discussed below, the drainage channels would be outside the plant and the security fencing but still within the project ROW.

Drainage and Earthwork

The existing topographic conditions of the project site show an average slope of approximately one foot in 67~~80~~ feet (1.50~~25~~%) toward the east on the west side of the site and approximately one foot in 200 feet (0.50%) toward the southeast on the east side of the site. The project site lies in the Palo Verde Mesa east of the McCoy Mountains. The general stormwater flow pattern is from the higher elevations in the mountains located three miles west of the site to the lower elevations in the McCoy Wash to the east of the site.

The applicants filed a Streambed Alteration Agreement for the purposes of altering the terrain and installing channels. This application is currently being reviewed.

Drainage will be constructed in two phases: Phase One accommodates the necessary drainage for the construction of Units 1 &2, and Phase Two the drainage plan for the entire four unit facility. In Phase One, two of the five major channels will need to be built for Units 1 and 2: the entire length of the North Channel plus diffuser, and the entire length of the Central channel plus diffuser. Only the portion of the West channel that bounds the southwest corner of Unit 2 will need to be constructed; the remainder of the West channel will not be needed until Units 3 and 4 are built. The southern boundary of Unit 2 will need to be protected with a berm from the West channel eastward to the point where the Central channel begins. Arizona crossings would be employed to provide adequate drainage across the access road into the site would preferably be accomplished with Arizona crossings. Phase Two will implement the fully constructed drainage plan for the entire facility, which was previously submitted to Staff.

~~terrain and installing channels. This application is currently being reviewed.~~

B.1.3 CONSTRUCTION

Project construction is expected to occur over a total of 69 months. Project construction would require an average of 604 employees over the entire 69-month construction period, with manpower requirements peaking at approximately 1,004 workers in Month 16 of construction. The construction workforce would consist of a range of laborers, craftsmen, supervisory personnel, support personnel, and management personnel.

Temporary construction parking areas would be provided within the project site adjacent to the laydown area. The plant laydown area would be utilized throughout the build out of the four solar units. The construction sequence for power plant construction includes the following general steps:

Site Preparation: this includes detailed construction surveys, mobilization of construction staff, grading, and preparation of drainage features. Grading for the solar fields, power blocks, and drainage channels would be completed during the first 55-months of the construction schedule.

Linears: this includes the site access road, telecommunication line, natural gas pipeline, and transmission line. The site access road and telecommunication line for Unit #1 would be constructed during the first nine months of the construction schedule in conjunction with plant site preparation activities. The natural gas pipeline, electric transmission lines, and telecommunications lines would be constructed during the first 18 months of the construction schedule.

Foundations: this includes excavations for large equipment (STG, SSG, GSU, etc.), footings for the solar field, and ancillary foundations in the power block.

Major Equipment Installation: once the foundations are complete, the larger equipment would be installed. The solar field components would be assembled in an onsite erection facility and installed on their foundations.

B.1.3.1 CONSTRUCTION WATER

Construction water requirements cover all construction related activities including:

- Dust control for areas experiencing construction work as well as mobilization and
- demobilization,
- Dust control for roadways,
- Water for grading activities associated with both cut and fill work,
- Water for soil compaction in the utility and infrastructure trenches,
- Water for soil compaction of the site grading activities,
- Water for stockpile sites,
- Water for the various building pads, and
- Water for concrete pours on site.

- Concrete batch plant operations

The predominant use of water would be for grading activities which would have a steady rate of work each month. The grading schedule for the site has been spread to cover the total construction period and there should be no definable peak but rather a steady state condition of water use. The average water use for the project is estimated to be about 645~~499~~,000 gallons per calendar~~working~~ day. Total water use for the duration of project construction is estimated to be about 4~~3~~,100 acre feet. Construction water would be sourced from onsite wells. Potable water during construction would be brought on site in trucks and held in day tanks.

B.1.3.2 CONCRETE BATCH PLANT

With the estimated concrete volume of approximately 125,000 cubic yards per solar plant, an onsite batch would be utilized to provide concrete for the solar fields and power block foundations and pads. The batch plant would have a production capacity of 150 cubic yards per hour and operate 10 hours per day, 5 days a week. Night operation of the batch plant will likely be required to overcome the difficulty of performing concrete placement in extremely high ambient temperatures. It would consist of a series of storage bins and piles, conveyors, mixers, ice storage and chipper, and would include a 75 kW power supply (with diesel generator if needed) and provision for dust control. Concrete would be transported from the batch plant to the placement area via a fleet of 8 concrete trucks. The batch plant would be movable and would be deployed to the current area of work at the power blocks or main warehouse area.

B.1.3.3 FUEL DEPOT

A fuel depot would be constructed to refuel, maintain, and wash construction vehicles, and would occupy an area of approximately 75 feet x 150 feet. It would consist of a fuel farm with two each 2000-gallon on-road vehicle diesel tanks, two 8,000-gallon off-road vehicle diesel tanks, one 500-gallon gasoline tank, and a wash water holding tank. The fuel farm would include secondary spill containment, a covered maintenance area, also with secondary containment, and a concrete pad for washing vehicles.

B.1.3.4 Construction Power

Construction power will be provided to the site from the Southern California Edison 12.47 kV distribution line routed to the site from SCE’s distribution poles 1 mile east of BSPP at the corner of Sixth Avenue and Davis St. The project will include construction of a 12.47 kV internal distribution system and step down transformers to provide power as needed to construction operations.

B.1.4. OPERATION AND MAINTENANCE

While electrical power is to be generated only during daylight hours, BSPP would be staffed 24 hours a day, seven days per week. A total estimated workforce of 221 full time employees would be needed with all four units operating.

B.1.4.1. NATURAL GAS PIPELINE CONSTRUCTION

A new four-inch diameter, 9.8-mile long natural gas pipeline would be constructed ~~by SCG~~ to connect the Blythe project to an existing SCG pipeline situated south of I-10. Approximately eight miles would be within the plant site boundary and two miles outside the plant site boundary. The line would be buried with a minimum three feet of cover depending on location. The gas line route takes off from an existing SCG line 1,800 feet south of I-10. The alignment of the pipeline is directly north to the project site.

Construction of the gas pipeline would be built to~~the responsibility of~~ SCG standards and is anticipated to take three to six months. Most major pieces of pipeline construction equipment would remain along the pipeline ROW during construction with storage and staging of equipment and supplies located at the Blythe project site or other acceptable site selected by SCG at the time construction is underway. Excavated earth material would be stored within the construction ROW.

There is an existing gas line running through a portion of the site that has been abandoned in place. The existing line will be removed as necessary during construction.

B.1.4.2. TRANSMISSION SYSTEM

The BSPP facility would be connected to the SCE transmission system at the new Colorado River substation planned by SCE approximately five miles southwest of the Blythe project site. The proposed generator-tie line would consist of a bundled double circuit 230 kV line.

B.1.4.3. TRANSMISSION LINE ROUTE

The ~~Although the~~ route has now~~not~~ been finalized. Generally speaking, the gen-tie line will ~~is expected to~~ proceed directly south from the project site ~~power block~~, eventually both crossing I-10 and turning westward to SCE's planned Colorado River substation.

Discussions are still ongoing with SCE regarding where the BSPP gen-tie will loop into the substation: either from a breaker in the north or the south of the substation site plan. Location of the breaker assigned to BSPP will be included in the Phase Two Study for the Transition Cluster from CAISO, currently expected by July 2, 2010.

B.1.5 DECOMMISSIONING AND RESTORATION

The planned operational life of the project is 30 years, but the facility conceivably could operate for a longer or shorter period depending on economic or other circumstances. If the project remains economically viable, it could operate for more than 30 years. However, if the facility were to become economically non-viable before 30 years of operation, permanent closure could occur sooner. In any case, a Decommissioning Plan would be prepared and put into effect when permanent closure occurs.

The procedures provided in the decommissioning plan would be developed to ensure compliance with applicable LORS, and to ensure public health and safety and protection of the environment. The Decommissioning Plan would be submitted to the CEC and BLM for review and approval prior to a planned closure.

ATTACHMENT 2

ENVIRONMENTAL EVALUATION OF PROJECT UPDATES

Minor Changes to the Blythe Solar Power Project

Palo Verde Solar I, LLC (PVSI) has made various minor modifications to the Blythe Solar Power Project (BSPP) since the Application for Certification (AFC) was submitted in August 2009. These minor changes are not reflected in the March 2010 Staff Assessment/Draft Environmental Impact Statement and reflect further definition of linear facilities and other changes required as a result of our discussions with Staff, other regulatory agencies and our construction team. The following pages briefly describe the various changes and evaluate their environmental implications for the BSPP, i.e., the effects of these changes (if any) on the existing analysis of Project impacts.

The Project changes discussed below include:

- Removal of the four Gas-Fired Heat Transfer Fluid (HTF) Heaters (one per Unit);
- Addition of an On-site Concrete Batch Plant During Construction;
- Addition of Evaporation Ponds to Process Industrial Wastewater Flows;
- Revision to Construction Water Requirements, Number of Groundwater Wells, and Construction Water Storage Approach;
- Finalization of the Gen-Tie Line Route to the Southern California Edison (SCE) Colorado River Substation;
- Clarification on the Removal of the Existing On-site (Abandoned) Natural Gas Pipeline;
- Changes to Layout of Project Facilities;
- Revisions to Project Drainage System Construction Sequencing;
- Clarification on the Paving of Black Rock Road;
- Addition of a Temporary Construction Power Line from Off-Site;
- Refinement of the Daily Construction Schedule;
- Finalization of the Telecommunications Line;
- Revised List of Water Treatment Chemicals; and
- Addition of an On-site Fuel Depot

REMOVAL OF GAS-FIRED HTF HEATERS

To eliminate the problem of HTF freezing, a gas-fired HTF heater, rated at 35 million British thermal units per hour, was proposed in the AFC for each of the four Units to ensure that the HTF system temperature would stay above the HTF freezing point of 54 degrees Fahrenheit (°F) (12 degrees Celsius [°C]). As proposed, the HTF heaters would each operate approximately 50 hours per year.

PVSI has decided to eliminate the separate gas-fired heaters and instead use the Project's proposed auxiliary boilers as the source of heat for HTF freeze protection. During the coldest winter nights, each auxiliary boiler, which will typically run at 25 percent capacity overnight to provide steam for the steam seals in the Steam Turbine Generator (STG), will now be utilized at 100 percent capacity to also provide steam to an HTF heat exchanger. Thus, instead of a fired HTF heater in each power block, the Project will use an *unfired heat exchanger* that utilizes steam from the auxiliary boiler as the heating medium. The new heat exchangers will be a shell and tube type design and will utilize 165 pounds per square inch gauge saturated steam from the auxiliary boilers as the heating medium.

Implications for Project Impact Analysis:

This modification will not lead to any additional ground disturbance beyond that already expected, nor will it have any substantial effects on water use, noise emissions, chemicals use, waste discharges, etc. The topical area that requires closer examination to establish potential implications for Project impacts is Air Quality.

Based on the system performance modeling, historical ambient temperature data and cost considerations, PVSI has determined that the HTF heaters will not be needed for Project operations. Instead, the heat required for HTF freeze protection will be provided by the auxiliary boilers. PVSI has determined that 100 hours of operation per year by each auxiliary boiler will be sufficient for HTF freeze protection.

Each auxiliary boiler will be used to support rapid startup each morning, specifically to establish the steam seals in the STG and maintain the air-cooled condenser (ACC) in an evacuated condition so that the Facility can generate power as soon as the solar-generated steam is sufficient to drive the steam turbine. In addition, each auxiliary boiler will be used for HTF freeze protection up to a maximum of 10 hours per day, and up to a maximum of 100 hours per year. The auxiliary boilers will not be used directly for power generation. The maximum daily operation of each boiler is expected to be 15 hours per day at 25 percent load, two hours per day at full load for start up support, and up to 10 hours per day for HTF freeze protection. The maximum daily operation of each boiler for these three purposes would not occur on the same day. Operating hours are summarized in Table Air-1, and the resulting emissions are summarized in Table Air-2. Revised emission estimates are provided in the spreadsheet titled Operation Emissions found in Appendix D to this Attachment.

ADDITION OF CONCRETE BATCH PLANT

With the anticipated requirement for approximately 125,000 cubic yards of concrete for each of the four solar plants of the BSPP, PVSI has decided include an on-site concrete batch plant to provide a cost-effective and reliable source of concrete for the solar field and power block foundations and pads. The batch plant will have a production capacity of 150 cubic yards per hour and is expected to operate 10 hours per day, five days a week. Night operation of the batch plant will be required to overcome the difficulty of performing cement pours in extremely high ambient temperatures (see **Refinement of the Daily Construction Schedule**). It will consist of a series of storage bins and sand/aggregate piles, conveyors, ice storage and chipper, and provision for dust control. The plant requires a 75-kilowatt power supply of line power (or a diesel generator). Concrete will be transported from the batch plant to the on-site placement area(s) via a fleet of eight cement trucks. The proposed batch plant is portable and will be moved to a number of different locations to support current work activities. Likely deployment locations are the four power blocks and the Project's main warehouse area. See drawing of the Preliminary Site Plan for batch plant location.

Implications for Project Impact Analysis:

PVSI has evaluated the overall elapsed time for a standard ready-mix concrete truck to travel from the existing commercial ready-mix facility in Blythe to the BSPP Site with allowances for the time required to pass through security, on-road travel and off-road travel within the Site and determined that the time exceeds the recommended time between cement preparation and pour. Thus, PVSI has determined that a temporary concrete batch plant will be required on site for Project construction.

Providing the concrete batch plant on site does not change the amount of concrete required for Project construction. It merely means that the raw materials (sand, aggregate, etc.), and plant components (storage bins, mixers, etc.) will be delivered to the Site rather than having ready mix cement trucks deliver product from an off-site batch plant location. An on-site batch plant will not disturb land that otherwise would not already be disturbed by the Project.

Air pollutant emissions for the batch plant are estimated using EPA AP-42 emission factors for each individual step in the concrete production process. Emissions are estimated for storage piles (sand, gravel, cement additive), weigh hopper loading, conveyor transfers, silo loading and discharge, and mixer loading. The weigh hopper loading and conveyor transfers for sand and gravel will operate with water sprays for dust emissions control, and both the silo and the mixer loading will operate with baghouse dust controls. Daily emissions are estimated based on a maximum production volume for the batch plant of 150 cubic yards per hour, 10 hours per day, with a total concrete requirement of 125,000 cubic yards per power block. In addition, the batch plant will require 75 kW of temporary construction power (see **Addition of a Temporary Construction Power Line from Off-site**) and will require the dedicated operation of one front-end loader. Emissions for the generator are based on Tier 2 engine emission factors and emissions from the front-end loader are based on the OFFROAD emissions model. Emission estimates for the batch plant are shown in Table Air-3. Detailed emission calculations are provided in the spreadsheet titled Batch Plant Emissions provided in Appendix C to this Attachment.

The batch plant emissions were incorporated into the revised ambient air quality modeling that was conducted for the construction phase of the BSPP. Please see the air quality evaluation below under the heading titled “Refinement of the Daily Construction Schedule” for a discussion of the modeling procedure and results.

Batch plant operation requires water and batch plant water supply needs are included in a revised Project construction water volume of 4,100 acre-feet. A separate discussion is provided below of the changes in Project water requirements under the heading titled “Revision to Construction Water Requirements, Number of Groundwater Wells, and Construction Water Storage Approach”. That section addresses changes to the Palo Verde Mesa Groundwater Basin water balance and cumulative impacts assessment and the potential impact to adjacent water supply wells from increased Project groundwater pumping during construction. .

The batch plant, along with the other Project construction activities, would be regulated under Riverside County noise ordinance requirements for construction activities. The County noise ordinance establishes limits for construction activities within ¼ mile of an existing residence. Because plant operations would not occur near the boundary of the BSPP Site, they also would not occur within ¼ mile of the nearest residence. The County noise ordinance does not limit construction noise levels. Batch plant noise levels would be approximately 90 decibels at 50 feet (depending on design). The batch plant noise levels are somewhat higher than the construction noise levels addressed at the Site boundary in the AFC noise analysis. However, the fact that this source would be located away from the boundary of the remote BSPP Site allows greater distance for noise attenuation. Project noise impacts would not be substantially different because of the temporary on-site operation of a concrete batch plant.

With respect to hazardous materials issues, batch plant operations will require use of some low-toxicity hazardous materials, such as fly ash and/or calcium chloride. However, the impacts of the temporary use of these materials would not substantially affect Project hazardous materials impacts and they would remain less than significant.

From a waste management perspective, batch plant operations will generate minimum amounts of waste concrete (i.e., daily clean out of cement trucks) and baghouse or other dust control equipment particulates. The batch plant will recycle materials (e.g., sand, gravel, and water) wherever possible to minimize the volume of waste. Project waste management impacts would remain less than significant.

The on-site batch plant would eliminate the ready-mix concrete truck trips associated an off-site batch plant. This would be offset by truck trips delivering concrete making materials to the Site. Overall, Project traffic impacts would be unchanged.

Because no additional land disturbance would result from the on-site batch plant, impacts would be unchanged with respect to biological, cultural, and other natural resources.

ADDITION OF EVAPORATION POND(S) TO MANAGE INDUSTRIAL WASTEWATER FLOWS

As previously proposed, reject water from the Project's water treatment system (reverse osmosis [RO]) concentrate would have been used for on-site dust suppression, however, this approach was found to be problematic by the RWQCB because of their designation of the RO concentrate as a waste stream, which effectively eliminates the option of land disposal. Subsequently, PVSI decided to abandon this approach. Instead, after first maximizing the amount of recycling of waste streams through use of the High Efficiency Reverse Osmosis (HERO) system for recovery, PVSI has decided to use evaporation ponds to manage on-site industrial waste streams. Ongoing Project design development has determined that waste streams such as blowdown from the small wet auxiliary cooling tower and blowdown from the auxiliary boiler may in certain cases not be recoverable in the HERO system and these streams will be sent to the on-site evaporation pond(s).

PVSI plans to construct two 4-acre evaporation ponds in each power block. Two ponds were selected for reliability. The plant will utilize one of the two ponds for approximately 24 months, and then switch to the other. When one pond requires maintenance or solids removal, BSPP can still operate with the other pond. The evaporation ponds will be double-lined and will meet all applicable regulatory requirements for surface impoundments and will be covered with narrow-mesh netting to prevent access by ravens and migratory birds.

Implications for Project Impact Analysis:

The proposed evaporation ponds will disturb no additional land surface areas beyond what was previously analyzed. While the residue in the evaporation ponds represent an additional waste stream that will require off-site disposal, the volume and infrequency of such disposal would not change the Project's less-than-significant waste management impacts.

A primary concern with evaporation ponds is potential biological resources implications. Incorporation of evaporation ponds into the Project design could potentially modify Project impacts in two ways, both related to the attraction posed by the ponds to avian species. First, the ponds may attract ravens in numbers beyond those afforded by the normal, arid conditions extant in the Project vicinity. A larger raven population increases the potential for predation of juvenile desert tortoises. The ponds also represent an attractant to other migratory and resident avian species. Chemicals present in the evaporation pond water potentially could be harmful to these species. In addition, measures taken to prevent access to water surfaces may themselves put birds at risk.

Biological resources mitigation planning for the BSPP already includes development of a Raven Management Plan. This Plan will be revised to incorporate measures that will be taken to prevent potential adverse effects to desert tortoises as a result of a subsidized raven population. The Plan will entail exclusion netting designed to prevent access to the water surface by ravens. The Raven Management Plan will also detail the measures taken to preclude access to the water surface by other avian species, and to prevent avian species from being harmed in any way by the exclusion devices.

Evaporation ponds, along with the Project's proposed Land Treatment Unit (LTU), have the potential to impact underlying groundwater and surface water quality. A report of waste discharge (ROWD) has been submitted describing the design, operation, management and detection monitoring program for the LTU. At this time, the evaporation pond design is still under development; a complete description of this Project element, including pond design, construction and maintenance, wastewater process and characterization along with a detection monitoring program will be part of the ROWD application to the Colorado River Basin Regional Water Quality Control Board (RWQCB), which is anticipated in May of 2010.

Construction and operation of the evaporation ponds will not affect the type or quantity of hazardous materials used by the BSPP. The waste streams will be the same with or without evaporation ponds. At least a portion of the discharge from the Project's auxiliary cooling towers and boilers will be routed to the evaporation ponds. Blowdown that bypasses the HERO and is discharged to the evaporation ponds will still contain solids and other chemicals (e.g., corrosion inhibitor), which means the blow down will be classified as a designated liquid waste. Solids (suspended and total dissolved solids) will be present and unchanged whether the blowdown is routed completely through the HERO or a portion of the blowdown is routed to the HERO and the evaporation ponds. As mentioned above concerning potential water resources impacts, the operator of an evaporation pond is required to submit a ROWD and obtain a Waste Discharge Requirements (WDR) permit from the RWQCB. The WDR will describe the design criteria, monitoring and sampling protocol, and other management criteria to minimize a release to the environment. The waste volumes associated with periodic cleanout of the dried evaporation pond residues would not significantly affect available disposal facilities.

On-site evaporation ponds will not have a substantial effect on the Project's air quality impacts. The process of evaporation pond construction is expected to have minimal effect on Project construction-phase air quality impacts. Earthwork (cut and fill, grading, and compaction), and other activities (e.g., truck trips delivering clay for pond liners) associated with pond construction would slightly change Project construction emissions. Air quality impacts of evaporation pond operation would be minimal.

REVISION TO CONSTRUCTION WATER REQUIREMENTS, NUMBER OF GROUNDWATER WELLS, AND CONSTRUCTION WATER STORAGE APPROACH

There has been no change in the Project's plan to supply construction and operation-phase water to the Project from on-site wells. The anticipated Project construction water demand is now 4,100 acre-feet (average of ~640,000 gallons per calendar day over the 69-month construction period). This is an increase of 1,000 acre-feet above the 3,100 acre-feet per year (afy) requirement identified in the BSPP AFC. Expected water usage during Project operation has not changed. The Project (all four solar units) will require a total of approximately 600 afy.

To supply the needed quantity of water, and based on the uncertainty in well yield due to the limited number of well tests performed to date, PVSI now expects to install up to two wells in each of the four power blocks (the second well provides redundancy in case of outages or maintenance needs of the first well). Two on-site wells near the central warehouse are proposed in addition to the pair of wells in each power block. This is an increase in the number of on-site wells compared to the AFC.

Water for construction activities including dust control, soil excavation and compaction, equipment flushing, etc., will be stored on site in temporary tanks. The temporary tanks are envisioned as "Baker Tanks," which are steel fixed axle tanks /vehicles that can be pulled to the Site and set at any convenient location. Upon completion of the Project construction activity, the tanks will be removed from the Site in the same manner.

Implications for Project Impact Analysis:

The change in proposed construction water supply represents about a 30% increase over the previously estimated volume of 3,100 acre-feet. The impacts from the change were evaluated using the Cumulative Impacts Assessment spreadsheet (Soil and Water Table 5-17-10 [rev2]) and the numerical groundwater model provided in the data response of January 6, 2010. The cumulative impacts assessment was modified by only changing the construction water volume to the proposed 4,100 afy over a 5-year period beginning in 2011. The recharge and discharge elements (i.e., mesa "inflow" and "outflow") were not changed over the water balance provided in Table Soil and Water-179-2 (rev1) (no changes were made to this table; therefore it is not included here) under the assumption that the infiltration would be about 5 percent of precipitation. The forecast shows that the Project during construction will account for between 16 percent and 78 percent of the total water used by renewable energy projects proposed in the Palo Verde Mesa for a 5-year period starting in 2011.

The Project's operational water volume is unchanged and accounts for 13 percent of the total renewable water use, and represents about a 4 to 7 percent increase in the total water use within the Palo Verde Mesa under an assumption of no change in the base-year water demand or inflow and outflow estimates. While the cumulative forecast from all the current and future sources results in a short-term net annual deficit, depending on the assumption of aquifer storage, the cumulative decline across the Palo Verde Mesa is between about 4 and 15 feet. It would be anticipated that the water level decline would be greater in areas of higher water demand. As noted in the AFC, the proposed water use for the Project alone represents about 0.3 percent of the available water in storage in the Palo Verde Mesa Groundwater Basin. Given its fractional contribution to the total water use, the Project does not represent a cumulatively considerable contribution to the water resource impacts to the Palo Verde Mesa Groundwater Basin.

The groundwater model that was provided in the Data Response submitted January 6, 2010, was revised to reflect an updated volume of construction water supply for the BSPP. Table Soil and Water-191-1(rev1) was modified to incorporate the change in the construction water volume over the volume proposed in the AFC. For the numerical simulations, the total water volume (4,100 acre-feet) was applied over a 5-year period (60 months) as a conservative estimate of the construction water impacts as the Project construction period is proposed at 5.75 years or 69 months. No other changes were made in the operational water volume (600 afy) or aquifer characteristics in the model provided for the Data Response. While the operational volume was not changed, the full volume of water was segregated and applied through a pumping well at the northernmost part of each power block pumping at a rate of 150 afy (see Figure Soil and Water-1).

The modeling was focused on the Project only pumping scenarios (Run 1 and Run 2 from prior modeling). A cumulative analysis was not done as the change only involves the short construction period and the change in pumping was not significantly different than prior estimates of construction supply. Further, the Project only pumping results using the updated construction volume were not significantly different than prior modeling indicating the change is not significant. The model configuration and zonation (i.e., distribution) of transmissivity and storage coefficient were not changed over the configurations provided in Data Response No. 191 (January 2010). Run 1 (higher transmissivity) and Run 2 (lower transmissivity) from the Data Response, which were configured to include the pumping test results from TW-1, were updated only with the change to the construction water volume as shown on Table Soil and Water-191-1(rev1).

The model results are shown in Table Soil and Water-191-2(rev1). As can be seen in the results, the maximum drawdown occurs at the end of construction (see Figure Soil and Water-2 and Soil and Water-4). During the operational period, the pumping rate drops and is distributed uniformly in the area of the power blocks, as such so does the drawdown. It is also noted that at the end of operation, the drawdown is slightly larger than at the middle of operation due to prolonged pumping (see Table Soil and Water-191-2[rev1]). The impact to adjacent water supply wells was also assessed using the radius of influence from the construction and operational pumping wells to the 5-foot drawdown and 1-foot drawdown contours. The maximum distance at 1-foot drawdown occurs at the end of operation for either scenario, though there is no drawdown above 5 feet predicted beyond the Project footprint (see Figure Soil and Water-3 and Soil and Water-5). Additionally, during construction no off-site water supply wells are predicted to be affected by Project pumping causing a drawdown of 5 feet or more (Figure Soil and Water-2 and Soil and Water-4). The scenarios modeled reveal that no off-site well is expected to be affected to a drawdown of 5 feet or more by the Project pumping.

In a numerical groundwater flow model, inflows and outflows of the model domain can be obtained using the model flow budget for each simulation. The cumulative difference between the inflows and outflows is the storage change for the aquifer. As can be seen from Table Soil and Water-191-1 (rev 1), the largest net storage change occurs at the end of operation for either model scenario. Assuming a total recoverable storage of 5,000,000 acre-feet in the basin (DWR 1979), the impact of basin storage over the full term of the Project (30 years) is insignificant even for the largest storage change at the end of operation (0.42 percent).

The numerical modeling files are provided in Appendix E, which accompanies this submittal.

FINALIZATION OF THE GEN-TIE LINE ROUTE TO THE SCE COLORADO RIVER SUBSTATION

The selected route for the Gen-Tie Line to interconnect the Project with the SCE regional transmission system will start at the Project's on-site central switchyard located south of the Unit #1 solar field near the northwest corner of the Unit #4 solar field. Leaving the onsite central switchyard, the BSPP Gen-Tie Line will run west parallel to the southern edge of the Unit #1 solar field for approximately 0.5 miles, then turn south along the eastern edge of the Unit #3 solar field for approximately 1.2 miles. After a 0.25-mile jog to the southeast, it will then head straight south for approximately 3.0 miles and cross over the Interstate 10 (I-10) freeway. After crossing I-10, the route continues south for another 1.0 mile before making a jog to the southwest for 0.5 mile and then heading generally west for 3.25 miles to the eastern edge of the SCE Colorado River Substation. The total length of the route is approximately 9.8 miles. Upon reaching the Colorado River Substation, the BSPP Gen-Tie Line will turn north at the substation's eastern fence line, turn west at the substation's northern fence line, and enter the substation from the north to connect to the 230-kilovolt (kV) bus in the substation (See attached Site Plan and Boundary Drawing for details of the proposed T-Line route). The proposed Gen-Tie Line is no longer configured as a 500-kV, single-circuit transmission line as indicated in the AFC. It will now consist of a double circuit, 230-kV line on monopole structures. The conductor proposed for each of the transmission circuits is a single conductor 2156 mil "Bluebird" aluminum conductor, steel reinforced cable capable of carrying 1,623 A at 167°F (75°C).

SCE will build, own, and operate the new Colorado River Substation to interconnect the BSPP and other new energy projects to the grid. The substation will interconnect and be adjacent to the Devers-Palo Verde 500-kV Transmission system at a point approximately 1.5 miles south of I-10 and about 5.3 miles west-southwest of the I-10 Mesa Drive/Airport exit. The facility will occupy an area of approximately 82.6 acres, with perimeter dimensions of 1,500 feet by 2,400 feet. The major components of the Substation consist of electrical transformers, circuit breakers, switchgear, and other safety equipment. The Colorado River Substation will be provided with a perimeter security wall, minimum of 8-feet high, topped with a minimum of three strands of barbed wire.

Implications for Project Impact Analysis:

Selection of this route between the BSPP Site and the Colorado River Substation will not substantially modify previous analyses with respect to air quality or water resources. Previous analyses in these disciplines have included a Gen-Tie Line between BSPP and the Colorado River Substation and the differences between the selected route and the routes previously evaluated do not substantially change air emissions or water supply needs. The primary areas of concern with respect to the final Gen-Tie Line route are biological and cultural resources because the selected route includes areas not previously surveyed for biological and cultural resources.

With respect to biological resources, portions of the Gen-Tie Line outside the BSPP Site are outside the area surveyed for biological resources in 2009. Full protocol-level biological surveys for these additional areas are currently underway. It is anticipated that transmission line pole locations and access road construction will result in modest increases in impacts to Sonoran Creosote Bush Scrub and Desert Dry Wash Woodland vegetation. The current surveys will ensure a level of biological resource data matching that derived from the 2009 surveys. Upon completion of these surveys, the results and the related impact analyses will be forwarded to the California Energy Commission (CEC), Bureau of Land Management (BLM), and other reviewing agencies. In addition, any necessary additional mitigation provisions will be calculated.

With respect to cultural resources, portions of the Gen-Tie Line off of the BSPP Site are outside the area surveyed for cultural resources in 2009. Cultural resource surveys for these additional areas are currently underway in order to ensure a level of cultural resource data matching that derived from the 2009 surveys. Upon completion of these surveys, the results and the related impact analyses will be forwarded to the CEC, BLM and other reviewing agencies. The resources encountered will be incorporated into Project cultural resources evaluation and treatment programs.

With respect to transmission line safety and nuisance impacts, the electromagnetic field (EMF) is a function of the physical configuration of the transmission line and the voltage and current levels. An EMF study was prepared for a line voltage of 230 kV. No significant transmission line-related impacts were identified as a result of the Project studies and, as such, no additional mitigation is required. The double circuit BSPP transmission lines will operate at 230 kV and will have a conductor surface electric field strength significantly below 15 kV per centimeter because of the large (“Bluebird”) conductor chosen for the Project. Radio frequency interference and audible noise levels are not expected to be a concern during operation of the line. In addition, PVSI will install monopoles of a sufficiently limited height to ensure that the Project meets the height restrictions in the area of concern near the Blythe airport.

CLARIFICATION ON THE REMOVAL OF THE EXISTING ON-SITE (ABANDONED) NATURAL GAS PIPELINE

In the AFC, PVSI documented the existence of a natural gas pipeline that extends into the BSPP Site. Further investigation has revealed that this is a 4-inch distribution line that was abandoned in place in the late 1960s by the Southern California Gas Company (SCG). PVSI intends to remove the portions of the abandoned pipeline on the BSPP Site. This will involve cutting and capping the line at the Project Site boundary and removing the on-site portions of the line. PVSI is coordinating with SCG to ensure that the line removal is performed in accordance with applicable procedures and requirements.

Implications for Project Impact Analysis:

Removal of the natural gas pipeline will not involve the disturbance of any previously undisturbed land areas and thus there would be no additional or modified impacts to biological or cultural resources. There will be no changes in the amount of water needed for Project use, or changes to Site drainage and runoff. Removal of the pipeline will involve minimal changes in equipment use or the amount of earthwork needed for the Project and thus there would be negligible changes in Project air quality impacts.

CHANGES TO POWER BLOCK LAYOUT

Minor refinements have been made to the power block layouts for each of the four plants to be constructed at BSPP. Generally, these updates include a slightly enlarged ACC for improved STG performance in hot weather, adding new, lower capacity water tanks that have a smaller diameter but are slightly taller than described in the AFC; replacing the fired HTF heater with an unfired HTF heat exchanger and relocation and expansion of the water treatment area, which has been shifted to make room for the center header.

These changes are reflected in the attached drawing 2008-045E-PP-001ALT, Plot Plan, Air Cooled Condenser Option for a revised plot plan and power block layout.

Implications for Project Impact Analysis:

The proposed layout changes do not involve disturbance of any previously undisturbed ground surface areas. Thus, they would have no implications for existing analyses related to biological, cultural, or other natural resources. The changes would not substantially affect water use during construction or operation; the relatively minor changes to the sizes and layout of facilities within the BSPP Site will not substantially change the existing visual resources impact analysis. Relatively small changes to power block facilities in the interior of the 7,000-acre plus Site will be virtually unnoticeable from off-site locations.

The following paragraphs address the air quality implications of several proposed minor changes to the Project's emission sources, source locations, and modeling requirements, including:

- Reconfiguration of the power blocks;
- Additional use of the boilers to provide steam for the heat exchangers and removal of the HTF heaters;
- Increase in hours of operation of the cooling towers;
- Increase in the number of mirror wash events assumed in the air quality impacts analysis;
- Changes to the maintenance vehicle travel within the solar field;
- Elimination of the vehicle travel associated with use of RO concentrate for dust suppression; and
- Modeling to assess the U.S. Environmental Protection Agency's (EPA's) new 1-hour Nitrogen Dioxide (NO_2) standard (effective date April 12, 2010).

The reconfiguration of the power block by itself would be expected to have a negligible impact to the air quality impacts analysis. Moving an emission source relative to the fence line or other receptors would be expected to change the modeling results at any specific receptor; however, given the distance from the power block to the fence line, any changes in equipment location within the power block would have a negligible impact to a receptor at or beyond the fence line more than 1,000 meters away.

The changes related to the boilers and HTF heaters were discussed above under Removal of Gas-Fired HTF Heaters.

Based on additional information provided by the Project engineers, PVSI has determined that the wet cooling tower used for heat rejection of the lube oil and generator cooling loops will have to operate 24 hours per day rather than 16 hours per day as was stated in the AFC. The Applicant expects that the cooling tower will not operate at full capacity during the additional eight hours per day; however, emissions are estimated based on full load operation. The revised cooling tower emissions are shown in Table Air-4. The ambient air quality modeling analysis has been revised based on the emission increase. Modeling results are discussed in detail in Appendix B.

The AFC and subsequent Data Response replies contain inconsistent information regarding the frequency of mirror washing; the project description stated once per week during the winter months and twice per week during the summer months and the air quality analysis was based on washing once per month during the winter and twice per month during the summer. PVSI has confirmed that the information in the project description more accurately reflects the anticipated wash schedule. The emission estimates for mirror washing have been revised to reflect the more frequent wash schedule; the emission estimates are shown in Table Air-5. The modeling results have also been revised based on the correct wash schedule; modeling results are discussed below.

PVSI has developed a more comprehensive understanding of the maintenance inspection requirements for the solar field and has revised the maintenance vehicle mileage and corresponding emission estimates accordingly. Simply put, the maintenance inspection vehicles would travel perpendicular to the solar troughs and piping in the vicinity of the connectors rather than parallel to the troughs and piping. In this way, the travel distance for inspections and corresponding vehicle emissions are reduce substantially compared to initial estimates; the emission estimates are also shown in Table Air-5.

As noted elsewhere, because RO concentrate was designated as a waste product by the RWQCB, PVSI can no longer consider using RO concentrate for dust suppression and therefore will direct this wastewater stream to evaporation ponds for disposal. Consequently, water truck use associated with use of this RO concentrate water for dust suppression activities will not be required, and the emissions associated with the related water truck use would not occur. The maintenance vehicle emission estimates shown in Table Air-5 have been revised to eliminate the emissions associated with this water truck use, and the ambient air quality modeling results have been revised based on this Project change; modeling results are discussed and presented below.

Detailed emission calculations for each of these Project refinements are provided in the spreadsheet titled Operating Emissions in Appendix D to this Attachment.

Finally, the EPA has adopted a new ambient air quality standard for a 1-hour averaging period for NO_2, effective April 12, 2010. The Applicant has prepared a modeling analysis for the 1-hour NO_2 standard to demonstrate compliance with this requirement.

Based on the modeling evaluation, the total concentrations comprised of maximum modeled concentration plus maximum ambient background are below the CAAQS/NAAQS for all pollutants with the exception of the 24-hour PM10 CAAQS and NAAQS, annual PM10 CAAQS, and 1-hour NO_2 CAAQS.

In the case of PM10, the ambient background already exceeds the standards and Project contributions are relatively small (45 percent and 14 percent of the 24-hour and annual PM10 CAAQS, respectively).

In the case of 1-hour NO_2, only 2002 showed modeled impacts which, when added to the maximum ambient background, exceeded the 1-hour NO_2 CAAQS of 339 $\mu g/m^3$. The modeled exceedances occur at night under limited dispersion conditions and are principally due to emissions from the emergency generators. However, the emergency generators are unlikely to be tested at night so the modeling analysis is conservative. To refine the modeling analysis, AERMOD was rerun using the “Maxifile” option to determine how many hours produced impacts of at least 164 $\mu g/m^3$, which, when added to the maximum ambient background concentration of 175 $\mu g/m^3$ would exceed the CAAQS. The results showed that only three hours out of the three years modeled (i.e., an average of only one hour per year) had the potential to exceed the 1-hour NO_2 CAAQS.

As a further refinement, hourly NO_2 background data for the Palm Springs, California monitoring site were acquired from the US EPA AIRS database data repository (http://www.epa.gov/ttn/airs/airsaqs/detaildata/downloadaqsdata.htm). The actual ambient background NO_2 concentration for each hour was then added to the modeled concentration and compared to the CAAQS. When added to the time matched ambient background NO_2 concentration, all three hours with the potential to exceed the CAAQS fall well below the standard of 339 μg/m^3. As discussed above, the peak 1-hour NO_2 impacts for the BSPP during operations are modeled to occur at night and are caused almost entirely by emissions from the emergency diesel generators. Testing of emergency engines is unlikely to occur during nighttime hours, as simulated in the model for the three potential problem hours. The modeling results are therefore conservative and demonstrate that the NO_2 CAAQS is unlikely to be exceeded during operations at the BSPP.

A discussion of the modeling methodology and the modeling results are provided in the Modeling Report provided as Appendix A to this submittal. An archive of the modeling files is provided as Appendix B to this submittal.

REVISIONS TO PROJECT DRAINAGE SYSTEM CONSTRUCTION SEQUENCING

PVSI has decided to develop the BSPP drainage system in two phases: Phase One accommodates the necessary drainage for the construction of Units #1 and #2, and Phase Two accommodates the drainage plan for the entire four-unit facility. In Phase One, two of the five major channels will need to be built for Units #1 and #2: the entire length of the North Channel plus diffuser, and the entire length of the Central channel plus diffuser. Only the portion of the West channel that bounds the southwest corner of Unit #2 will need to be constructed; the remainder of the West channel will not be needed until Units #3 and #4 are built. The southern boundary of Unit #2 will need to be protected with a berm from the West channel eastward to the point where the Central channel begins. Drainage across the access road into the Site would be accomplished using Arizona crossings. Phase Two will incorporate the fully constructed drainage plan for the entire BSPP as previously submitted to Staff. Consistent with requests to provide 30% design and drainage plans, inclusive of revisions to Project drainage reports (COC S&W-11) and Project hydraulic analysis (COC S&W-12), sequencing of channel construction and potential changes to flow conditions are being evaluated. The objective is for the post Project downstream flow to reflect as closely as possible the existing flow regime. Revised drainage report and hydraulic analysis report to be provided 30 days prior to construction as per the identified Conditions of Certification (COCs).

Implications for Project Impact Analysis:

With respect to air quality, this proposed Project refinement is expected to reduce somewhat the earthwork (cut and fill, grading, compaction) required for the Project, which will reduce equipment tailpipe emissions and fugitive dust from earthwork activities. Ambient air quality modeling demonstrated no adverse air quality impacts from construction activities as construction was originally proposed (please see the impacts analysis presented in the AFC and subsequent Data Responses). A reduction in emissions is expected to reduce impacts to ambient air quality. This proposed refinement does not impact operating emissions from the BSPP facility.

With respect to biological resources, it is important to note that while the sequenced activities described above refer to tortoise fencing and potential relocation, only one live tortoise was encountered during the protocol surveys of the Site. Therefore, while encountering desert tortoise during clearance surveys must be provided for, it is not expected that a substantial number of tortoises would be encountered. Revisions to the grading and drainage sequencing will result in no appreciable changes to identified biological impacts. Irrespective of the timing of various project-related Site disturbances, all would occur within the identified Project disturbance footprint that has been subjected to comprehensive protocol surveys and for which mitigation measures have been formulated and will be implemented.

CLARIFICATION ON THE PAVING OF BLACK ROCK ROAD

Black Rock Road is the frontage road on the north side of the I-10 that will be used for access to the BSPP Site; the roadway currently is unpaved from just west of the intersection of I-10 and Black Mesa Road. PVSI intends to improve this roadway to County of Riverside standards from the point at which the pavement currently ends all the way to the point at which the BSPP Site access road intersects Black Rock Road. The existing right of way (ROW) is 60 feet wide and was relinquished by Caltrans to the County in 1974. The Riverside County specifications (see attached Figure Road-1, Access Road Cross Sections) will result in a roadway having a 50-foot ROW, that is two (16-foot) lanes wide (total of 48 feet graded with 32 feet paved), and 8-foot shoulders. The roadway section to be improved extends for a total length of approximately 3,500 feet.

Implications for Project Impact Analysis:

With respect to air quality impacts, paving Black Rock Road would require the application of asphalt, which has the potential to cause volatile organic compound (VOC) emissions. Based on a paved area of 3,500 feet by 32 feet, the total VOC emissions are expected to be 7.2 pounds. Paving of this road can be completed in less than one day. The VOC emissions from this Project element would not trigger any new regulatory requirements, and the emissions represent a small fraction of the daily VOC emissions during the construction period. The VOC emissions are not expected to cause a significant adverse impact to air quality resources. Paving emissions are shown in Table Air-6.

With respect to biological resources impacts, the Black Rock Road corridor is outside the area surveyed for biological resources in 2009. Full protocol-level biological surveys of the roadway alignment are currently underway. Potential biological effects are expected to be minimal as this improvement consists of the blading and paving of an existing dirt road segment flanked by the I-10 ROW and disturbed land. The current biological surveys will ensure a level of biological resource data matching that derived from the 2009 surveys. Upon completion of these surveys, the results and the related impact analyses will be forwarded to the CEC and other reviewing agencies. In addition, any necessary additional mitigation provisions will be calculated.

With respect to cultural resources impacts, the Black Rock Road corridor is outside the area surveyed for cultural resources in 2009. Cultural resource surveys for these additional areas are currently underway. These surveys will ensure a level of cultural resource data matching that derived from the 2009 surveys. Upon completion of these surveys, the results and the related impact analyses will be forwarded to the CEC and other reviewing agencies. The resources encountered will be incorporated into evaluation and treatment programs.

Concerning potential noise impacts, improving Black Rock Road will involve the use of noise-producing heavy equipment. However, the roadway to be improved is adjacent to I-10 with its attendant vehicle noise, and there are no residents in close proximity to Black Rock Road to experience any increases in noise levels. Therefore, no changes to the existing noise impacts analysis would be expected.

ADDITION OF A TEMPORARY CONSTRUCTION POWER LINE FROM OFF-SITE

Construction power will be provided to the Site from the SCE 12.47-kV distribution line routed to the Site from SCE's distribution poles located one mile east of BSPP at the corner of Sixth Avenue and Davis Street. The Project will include construction of a 12.47-kV internal distribution system and step-down transformers to provide power as needed to construction operations.

Implications for Project Impact Analysis:

Using temporary power lines rather than portable generators lowers Project air quality impacts during construction. The temporary power lines would require the installation of temporary power poles and conductor. Installation of the poles is a relatively short-term activity (less than 60 days), which would be conducted prior to the bulk of the construction activities, as the power is required for the construction activities. Consequently, operation of the drill rig for power pole installation would not contribute to peak daily construction emissions and would not significantly alter the annual emissions for any criteria pollutant. Emissions from power line construction are not modeled or otherwise evaluated. The installation of the temporary power lines would reduce the need for portable diesel-fueled generators and thus reduce nitrogen oxides, sulfur oxides, VOC, carbon monoxide and particulate matter emissions during the construction period compared to the Project as described in the AFC. Lower air quality impacts are anticipated as a consequence of this Project change.

With respect to biological resource impacts, the temporary construction power line corridor is outside the area surveyed for biological resources in 2009. Full protocol-level biological surveys of the alignment are currently underway. Potential biological effects are expected to be minimal as this improvement consists of the blading and paving of an existing dirt road segment, approximately one-half mile in length, and the temporary installation of wooden poles. The land on the south side of the dirt road is disturbed, as it was previously used for agriculture. The current biological surveys will ensure a level of biological resource data matching that derived from the 2009 surveys. Upon completion of these surveys, the results and the related impact analyses will be forwarded to the CEC, BLM, and other reviewing agencies. In addition, any necessary additional mitigation provisions will be calculated.

With respect to cultural resources impacts, the temporary construction power line corridor is outside the area surveyed for cultural resources in 2009. Cultural resource surveys for these additional areas are currently underway. These surveys will ensure a level of cultural resource data matching that derived from the 2009 surveys. Upon completion of these surveys, the results and the related impact analyses will be forwarded to the CEC, BLM, and other reviewing agencies. The resources encountered will be incorporated into evaluation and treatment programs.

REFINEMENT OF THE DAILY CONSTRUCTION SCHEDULE

Based on refinements to the Project construction plan, PVSI has determined that certain construction activities would have to be conducted at night in order to meet the Project schedule. The AFC identified that cement pours should be conducted at night as the high ambient temperatures during the daytime hours in the desert would jeopardize the quality of the concrete, as concrete dries too quickly if it is too hot.

PVSI also believes that solar collector assembly work would have to be conducted 24 hours per day to meet the construction schedule. In addition, to provide a more comfortable work environment, PVSI would like to allow for certain other low-noise construction activities to be conducted at night, including pulling wire and welding. These activities would require operation of the concrete batch plant, generators, light plants, welders, forklifts, possibly small cranes, and miscellaneous other equipment.

Implications for Project Impact Analysis:

The resource areas potentially affected by the clarification in the daily work schedule are primarily noise and air quality. Noise impacts potentially could be different because the additional work hours would occur outside normal work hours and include nighttime hours where ambient noise levels are lower than during the day. Also, the impacts of Project emissions on ambient air quality are affected by meteorological conditions. There are calm atmospheric conditions during non-daylight hours including the hours around dawn and dusk that must be taken into account when analyzing the impacts of construction activities in those times of the day.

With respect to noise impacts, PVSI is willing to accept a limitation on construction activities outside the previously proposed work hours that is consistent with the intent of Riverside County Noise Ordinance. This ordinance prohibits construction activities outside of specified hours when within ¼ mile of an existing residence, and PVSI has recommended modification of Condition of Certification NOISE-6 to make this limitation explicit.

With respect to air quality impacts, and based on refinements to the construction plan, PVSI has determined that certain low-noise construction activities, which do not involve grading or excavation work, would have to be conducted at night in order to meet the Project schedule. In the AFC and subsequent responses to Staff Data Requests, PVSI had proposed to limit construction activities to eight hours per day during the winter months and ten hours per day during the summer months. Under the original plan, only limited construction activities would occur at night, or during the early morning or late afternoon hours when stable atmospheric conditions prevail. PVSI provided ambient air quality modeling to demonstrate that under these circumstances, Project construction would not cause adverse air quality impacts.

Based on a review of the initial modeling results (i.e., in the AFC and subsequent Data Responses), PVSI has determined that the majority of the modeled impacts from construction activities were due to the heavy earthwork that would occur near the Project fence line. To evaluate the potential impact of the limited nightime operations, we have assumed that no earthwork would occur outside of the daytime schedule previously evaluated, and thus emissions from graders, scrapers and dump trucks would not occur. All other construction equipment is assumed to be operational. The emissions from the non-earthwork equipment were evaluated using the modeling approach and methods described in the AFC and Data Responses.

The results of the revised construction modeling indicate that all impacts, when added to the appropriate ambient backgrounds, are below their respective NAAQS/CAAQS with the exception of 24-hour and annual PM10, 24-hour PM2.5, and 1-hour NO_2. Project impacts alone are below their respective CAAQS with maximum concentrations of 43.0 micrograms per cubic meter (μg/m^3) for 24-hour PM10, 3.9 μg/m^3 for annual PM10, and 14.4 μg/m^3 for 24-hour PM2.5.

In the case of PM10 impacts, the maximum modeled 24-hour average and annual mean for PM10 exceed the CAAQS when background concentrations are added because the PM10 air quality monitoring station data used for this Project show that the PM10 CAAQS is already exceeded in the area where the data were collected, i.e., in Niland[1], California. Actual Project impacts from 24-hour PM10 represent 86 percent of the CAAQS and only 21 percent of the total impact when background is considered. For annual PM10, the Project impacts represent only 19.5 percent of the CAAQS for annual PM10 and only 11.6 percent of the total impact to the annual PM10 concentrations when the worst-case background is considered. Similarly for 24-hour PM2.5, the maximum modeled 24-hour average for PM2.5 exceeds the CAAQS when background concentrations are added because the PM2.5 air quality monitoring station data used for this Project is already over the CAAQS before Project impacts are considered. Actual Project impacts from 24-hour PM2.5 represent 41.2 percent of the CAAQS and only 34.8 percent of the total impact when background is considered.

For 1-hour NO_2, a total of 505 hours, or 1.9 percent of the 26,304 hours modeled, indicated impacts which, when added to the maximum ambient background concentration over the most recent 3 years of available data, exceeded the 1-hour NO_2 CAAQS. As an additional refinement, time-matched background data was added to each modeled impact, and the sum compared to the 1-hour NO_2 CAAQS. The maximum modeled concentration of Project impacts plus time matched ambient background is 335.9 $\mu g/m^3$, which is below the 1-hour standard of 339 $\mu g/m^3$, and thus compliance with the CAAQS is demonstrated.

A discussion of the modeling methodology and the modeling results are provided in the Modeling Report provided as Appendix A to this submittal. An archive of the modeling files is provided as Appendix B to this submittal.

Based on the results of the ambient air quality impacts analysis, the Project would not have an adverse impact to air quality resources given the constraints outlined within this discussion. These results do not change any of the conclusions in the SA/DEIS and no additional mitigation measures beyond those proposed by Staff are needed.

FINALIZATION OF THE TELECOMMUNICATIONS LINE

The Project will have telecommunications service from Frontier Communications, the telecommunications service provider for the City of Blythe. Voice and data communications would be provided by a new twisted pair telecommunications cable. The routing for this cable will follow the routing of the redundant telecommunications line from the BSPP Site to the Colorado River Substation. The routing for both of these lines will be adjacent to Black Rock Road and the Site access road. Wireless telecom equipment will be used to support communication with staff dispersed throughout the Site. The Project would utilize electronic telemetry systems to control on-site equipment and facilities operations.

Implications for Project Impact Analysis:

The addition of new telecommunications equipment to the BSPP would not substantially change Project impacts in any of the topical areas addressed in the AFC. The installation of this line is not expected to have an adverse impact to air quality resources because the construction requirements do not differ significantly from the construction plan and associated emissions presented in the

[1] Staff used different monitoring stations in their SA/DEIS.

In the case of PM10 impacts, the maximum modeled 24-hour average and annual mean for PM10 exceed the CAAQS when background concentrations are added because the PM10 air quality monitoring station data used for this Project show that the PM10 CAAQS is already exceeded in the area where the data were collected, i.e., in Niland[1], California. Actual Project impacts from 24-hour PM10 represent 86 percent of the CAAQS and only 21 percent of the total impact when background is considered. For annual PM10, the Project impacts represent only 19.5 percent of the CAAQS for annual PM10 and only 11.6 percent of the total impact to the annual PM10 concentrations when the worst-case background is considered. Similarly for 24-hour PM2.5, the maximum modeled 24-hour average for PM2.5 exceeds the CAAQS when background concentrations are added because the PM2.5 air quality monitoring station data used for this Project is already over the CAAQS before Project impacts are considered. Actual Project impacts from 24-hour PM2.5 represent 41.2 percent of the CAAQS and only 34.8 percent of the total impact when background is considered.

For 1-hour NO_2, a total of 505 hours, or 1.9 percent of the 26,304 hours modeled, indicated impacts which, when added to the maximum ambient background concentration over the most recent 3 years of available data, exceeded the 1-hour NO_2 CAAQS. As an additional refinement, time-matched background data was added to each modeled impact, and the sum compared to the 1-hour NO_2 CAAQS. The maximum modeled concentration of Project impacts plus time matched ambient background is 335.9 $\mu g/m^3$, which is below the 1-hour standard of 339 $\mu g/m^3$, and thus compliance with the CAAQS is demonstrated.

A discussion of the modeling methodology and the modeling results are provided in the Modeling Report provided as Appendix A to this submittal. An archive of the modeling files is provided as Appendix B to this submittal.

Based on the results of the ambient air quality impacts analysis, the Project would not have an adverse impact to air quality resources given the constraints outlined within this discussion. These results do not change any of the conclusions in the SA/DEIS and no additional mitigation measures beyond those proposed by Staff are needed.

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Implications for Project Impact Analysis:

The addition of new telecommunications equipment to the BSPP would not substantially change Project impacts in any of the topical areas addressed in the AFC. The installation of this line is not expected to have an adverse impact to air quality resources because the construction requirements do not differ significantly from the construction plan and associated emissions presented in the

[1] Staff used different monitoring stations in their SA/DEIS.

AFC, and there are no operating emissions associated with this equipment. Similarly, impacts to biological and cultural resources are not expected to change substantially because the proposed route is located in a corridor that has already been surveyed.

REVISED LIST OF WATER TREATMENT CHEMICALS

Additional water treatment chemicals will be required for the boiler, RO system, clarifier, multimedia filters, and cooling towers. These additional water treatment chemicals (beyond what has already been provided in AFC Table 5.6-3) include soda ash, lime, sodium hypochlorite, coagulant, magnesium chloride, polymer, anti-scalant, sodium bisulfate, corrosion inhibitor, dispersant, sodium hydroxide, scale inhibitor, biodispersant, phosphate, amine, and hydrazine. Currently, detailed engineering changes to the water treatment process are being prepared, and we expect the revised Table 5.6.3 showing all additional process chemicals including quantities, hazardous material and CAS #s, relative toxicity and hazard class, RQ, PEL, storage description and capacity, and storage practices/special handling precautions, etc. will be provided to the CEC within two weeks[HS1].

Implications for Project Impact Analysis:

Listed additional hazardous materials are typical water treatment chemicals; however, hazardous materials, such as sodium hydroxide, in sufficient concentration and quantity may trigger risk management plan or California Accidental Release Prevention requirements. All hazardous materials storage or process vessels will be designed in conformance with applicable American Society of Mechanical Engineers codes. Bulk storage tanks or totes will have secondary containment structures capable of holding the tank or tote volume plus an allowance for precipitation. Concrete containment structures will be coated with a chemical resistant coating to ensure long-term integrity of the containment structure.

As with all other aspects of the BSPP, appropriate safety programs will be developed to address hazardous materials storage and use, emergency response procedures, employee training requirements, hazard recognition, fire safety, first aid/emergency medical procedures, hazardous materials release containment/control procedures, hazard communications training, Personal Protective Equipment training, and release reporting requirements. In short, the additional chemicals on site would not affect Project impacts.

ADDITION OF AN ON-SITE FUEL DEPOT DURING CONSTRUCTION

A fuel depot will be constructed to refuel, maintain, and wash construction vehicles. It will occupy an area of approximately 75 feet by 150 feet and will consist of a fuel farm with two 10,000-gallon diesel tanks, one 500-gallon gasoline tank, and a wash water holding tank. Each diesel tank would be subdivided into two compartments, an 8,000-gallon compartment for off-road diesel fuel and a 2,000-gallon compartment for on-road diesel fuel. The fuel depot will include secondary spill containment; a covered maintenance area, also with secondary containment; and a concrete pad for washing vehicles. (Please see the attached Figure Depot-1, Fuel Depot Layout for a general representation of the proposed fuel depot.)

Implications for Project Impact Analysis:

The gasoline storage tank is subject to air permit requirements under Mojave Desert Air Quality Management District (MDAQMD) rules; the diesel tanks are exempt from permit requirements in the MDAQMD pursuant to Rule 219(E)(14)(c).

The emissions from the two 10,000-gallon diesel storage tanks and the 500-gallon gasoline storage tank proposed for BSPP were calculated using EPA's TANKS 4.09D tank emission estimation program and the maximum annual fuel usage during the construction and operational phases of the Project. The maximum annual fuel usage was calculated from the Carbon Dioxide (CO_2) emissions derived from the OFFROAD2007 and EMFAC2007 models for each equipment and vehicle type used during the construction of the Project. The CO_2 emissions were divided by the Air Resource Board's default CO_2 emission factor, which is based on the carbon content of the fuel, to estimate the fuel consumption. This method was selected to calculate fuel usage because the OFFROAD2007 model incorporates fuel economy and average load rates into the emission factors, so additional adjustments are not required. To prevent the underestimation of annual emissions, it was assumed that the maximum monthly fuel usage for the construction of the Project would occur every month. The maximum annual gasoline and diesel usage from the operation of BSPP was taken from the greenhouse gas emissions calculations submitted in the DR responses, using the same method as described for construction. Note that this method would overestimate the fuel throughput and corresponding tank emissions during both construction and operations because some of the equipment is expected to be refueled off site. Fuel Depot emissions are summarized in Table Air-7. Emission calculations are provided in the spreadsheet titled Operating Emissions provided as Appendix D to this submittal. The VOC emissions from these tanks are not expected to cause or contribute to a significant adverse air quality impact.

As noted in the BSPP AFC (page 5.6-12), diesel fuel is the hazardous material with the greatest potential for environmental consequences during Project construction due to the volume of diesel fuel that will be used in construction equipment and the frequent refueling that will be required. When refueling is needed, vehicles will enter a dedicated refueling area where secondary containment is present to minimize the impact to the environment. A dedicated location increases the ability to effectively manage spills, leaks, storage, handling, loading/unloading, and other activities associated with vehicle fueling. Any fuel spilled will be contained and promptly cleaned up with no contaminated soil generated. If anything, this Project change is expected to decrease the potential for environmental impacts associated with refueling spills.

Figures and Tables

BLYTHE SOLAR POWER PROJECT (09-AFC-6) **CEC STAFF ASSESSMENT – ENGINEERING CHANGES**
Response Date: April 15, 2010

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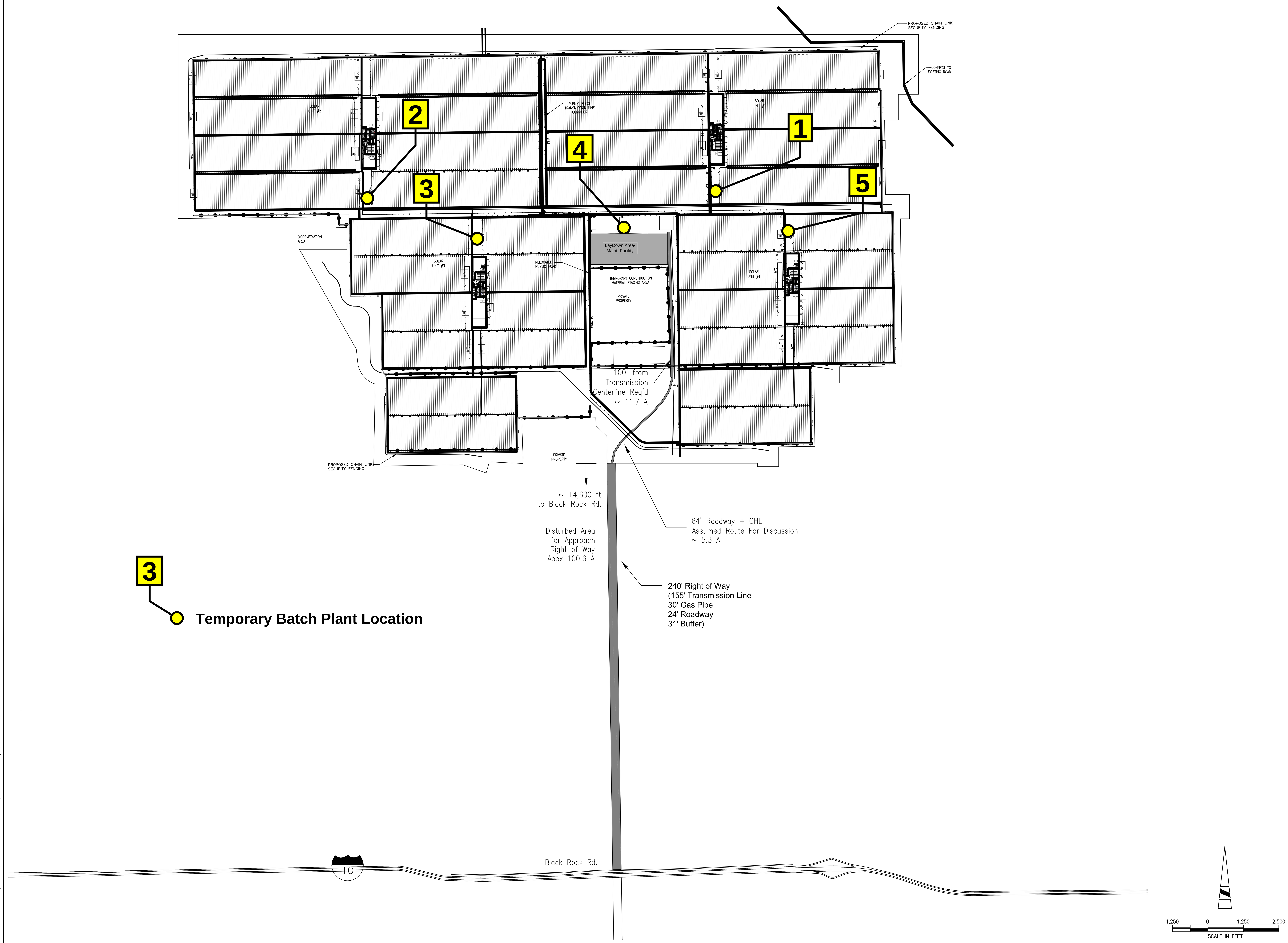

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Revisions:

#	DATE	DESCRIPTION

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Solar Millennium LLC

LEGEND:

- SOLAR BLOCK LOCATION
- BALANCE OF PLANT FACILITIES
- PROPOSED ACCESS ROAD (PAVED)
- PROPOSED ACCESS ROAD (GRAVEL)
- PROPOSED SILT FENCE
- FR PROPOSED FIBER ROLLS
- EB PROPOSED EARTH BERM
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- PROPOSED CONTOURS
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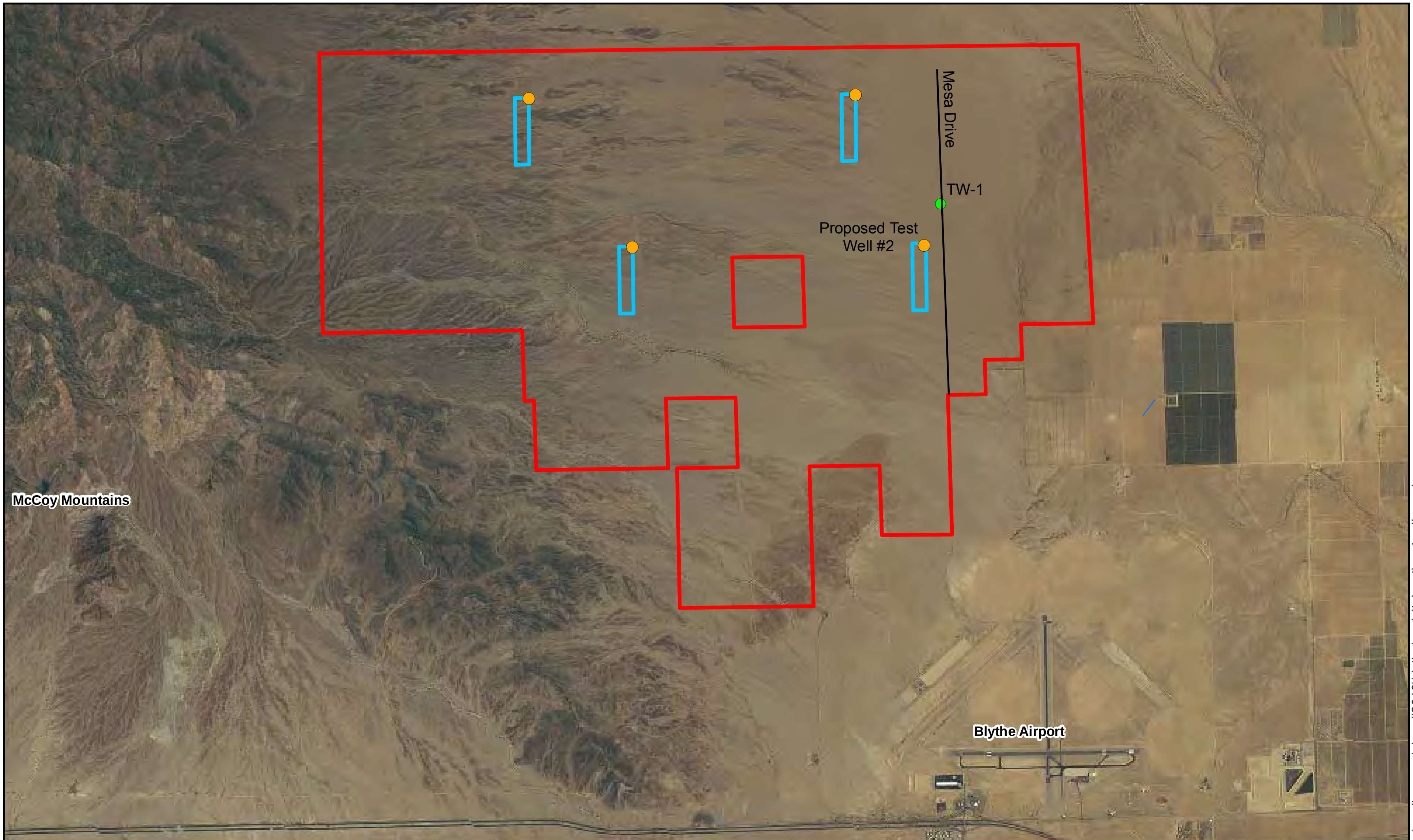
- PROPOSED FLOOD CONTROL
- EXISTING PAVED ROAD
- EXISTING GRAVEL ROAD
- EXISTING CONTOURS
- EXISTING STREAM LINE
- SITE BOUNDARY
- PUB. R. PUBLIC ROAD
- P.R. PRIVATE ROAD
- DC DRANAGE CULVERT

Blythe Solar Power Project

Riverside County, California

Preliminary Site Plan

Date: 8/07/09
Sheet: 3 OF 18



Map Location

Legend

- Project Right-of-Way
- Power Blocks
- Construction Water Supply (TW-1)
- Operational Water Supply

Data Sources:
Air Photo, California Spatial Information Library,
NAIP, 2009 Riverside County

Blythe Solar Power Project

Soil and Water
Figure 1
Pumping Well Locaitons

Palo Verde I, LLC

AECOM

Project: 60139695
Date: April 2010

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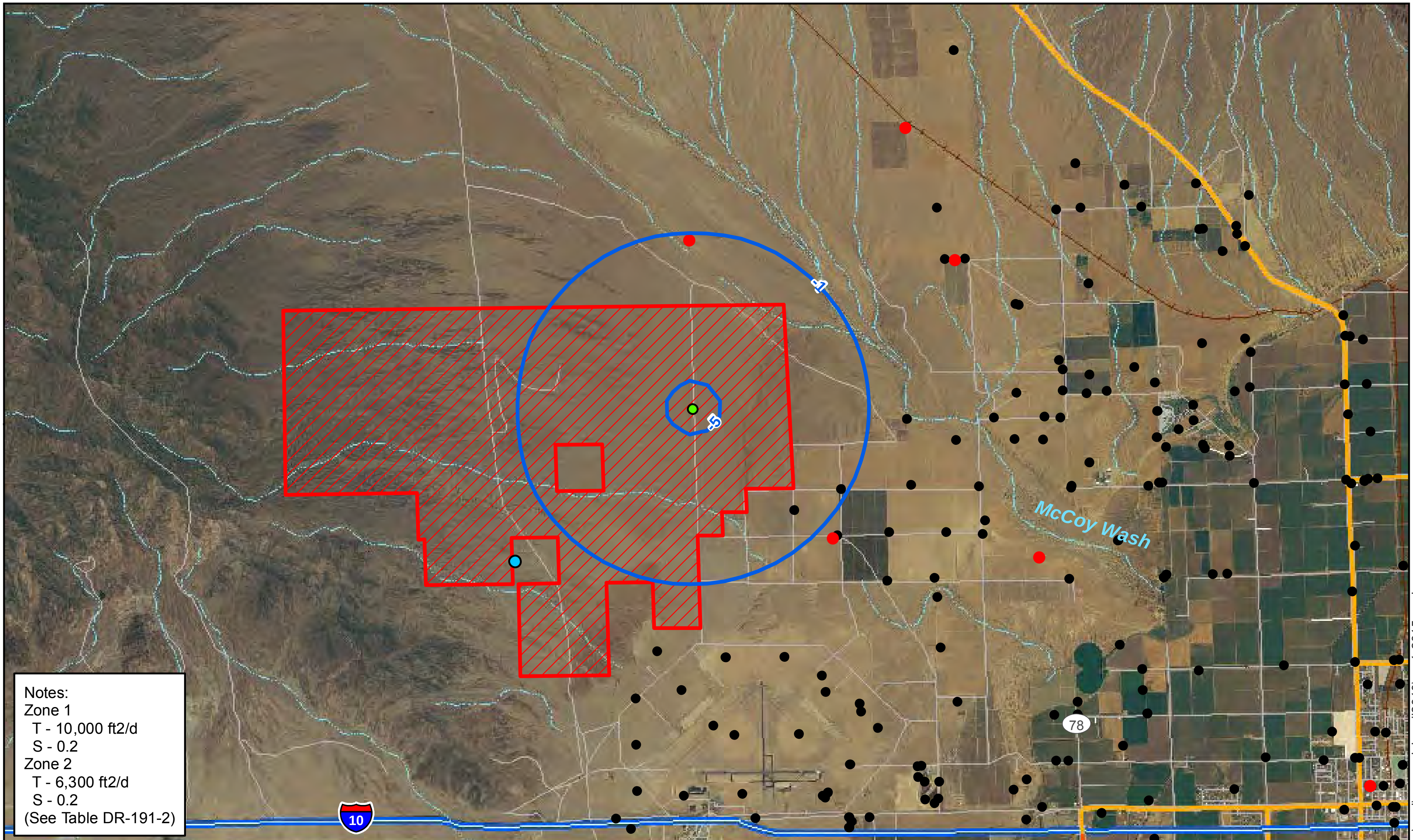

Map Location

Legend

- Contours of Drawdown (feet)
- Groundwater Wells Identified as Potentially Active in AFC
- Groundwater Well Location
- Pumping Well
- Possible Well Location Not Identified in USGS or DWR Database
- Blythe Solar Power Project Right of Way

1 inch = 8,000 feet — 0, 6,000, 12,000 Feet

Data Sources:
Air Photo, NAIP, 2005
Basemap, (Roads, streams, cities), ESRI

Blythe Solar Power Project

Soil and Water
Figure 2
Groundwater Modeling of Proposed Project Pumping
Run 1
Year 2015-End of Construction

Palo Verde I, LLC

AECOM

Project: 60139695
Date: April 2010

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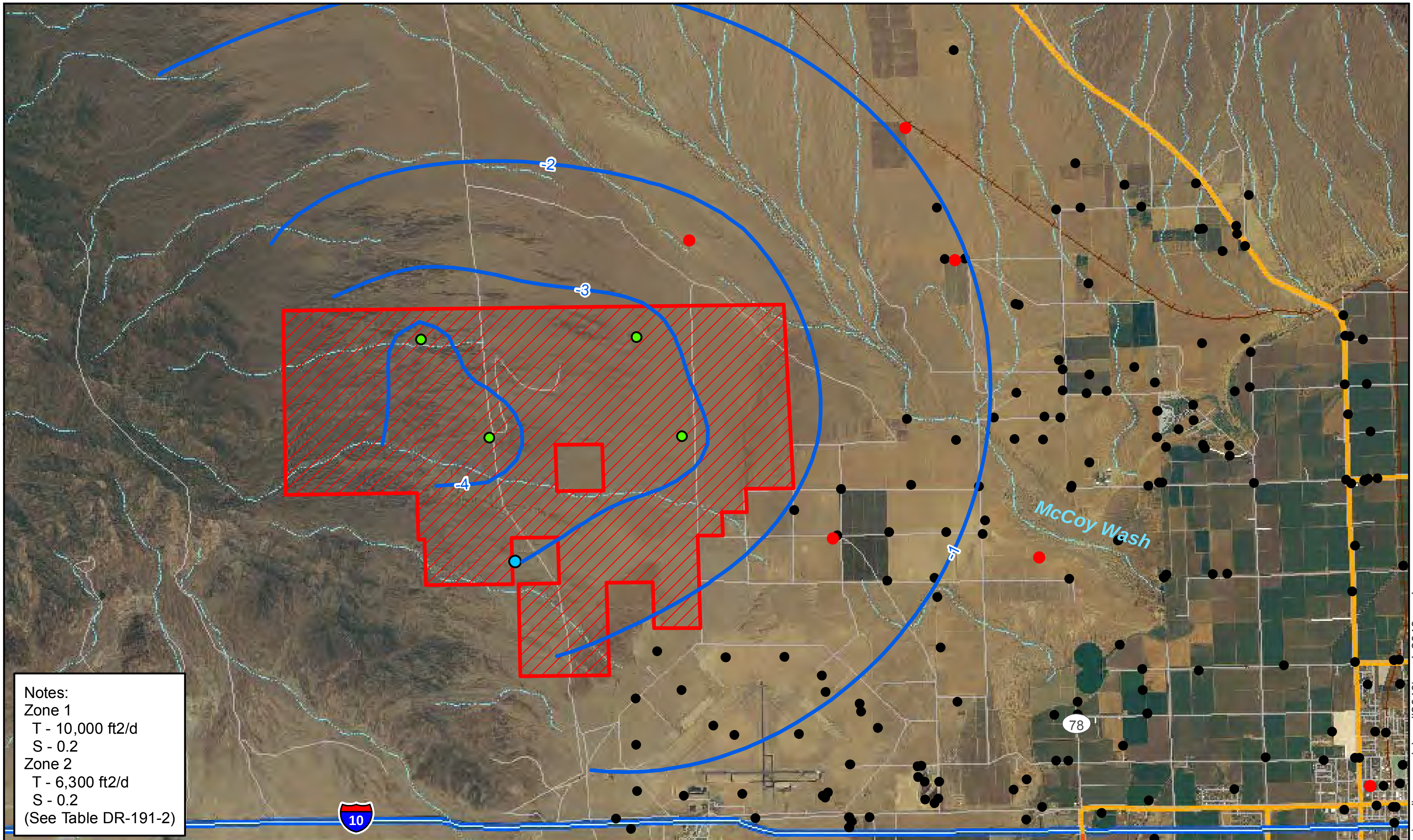

Map Location

Legend

- Contours of Drawdown (feet)
- Groundwater Wells Identified as Potentially Active in AFC
- Groundwater Well Location
- Pumping Well
- Possible Well Location Not Identified in USGS or DWR Database
- Blythe Solar Power Project Right of Way

1 inch = 8,000 feet — 0, 6,000, 12,000 Feet

Data Sources:
Air Photo, NAIP, 2005
Basemap, (Roads, streams, cities), ESRI

Blythe Solar Power Project

Soil and Water
Figure 3
Groundwater Modeling of Proposed Project Pumping
Run 1
Year 2043-End of Operations

Palo Verde I, LLC

AECOM

Project: 60139695
Date: April 2010

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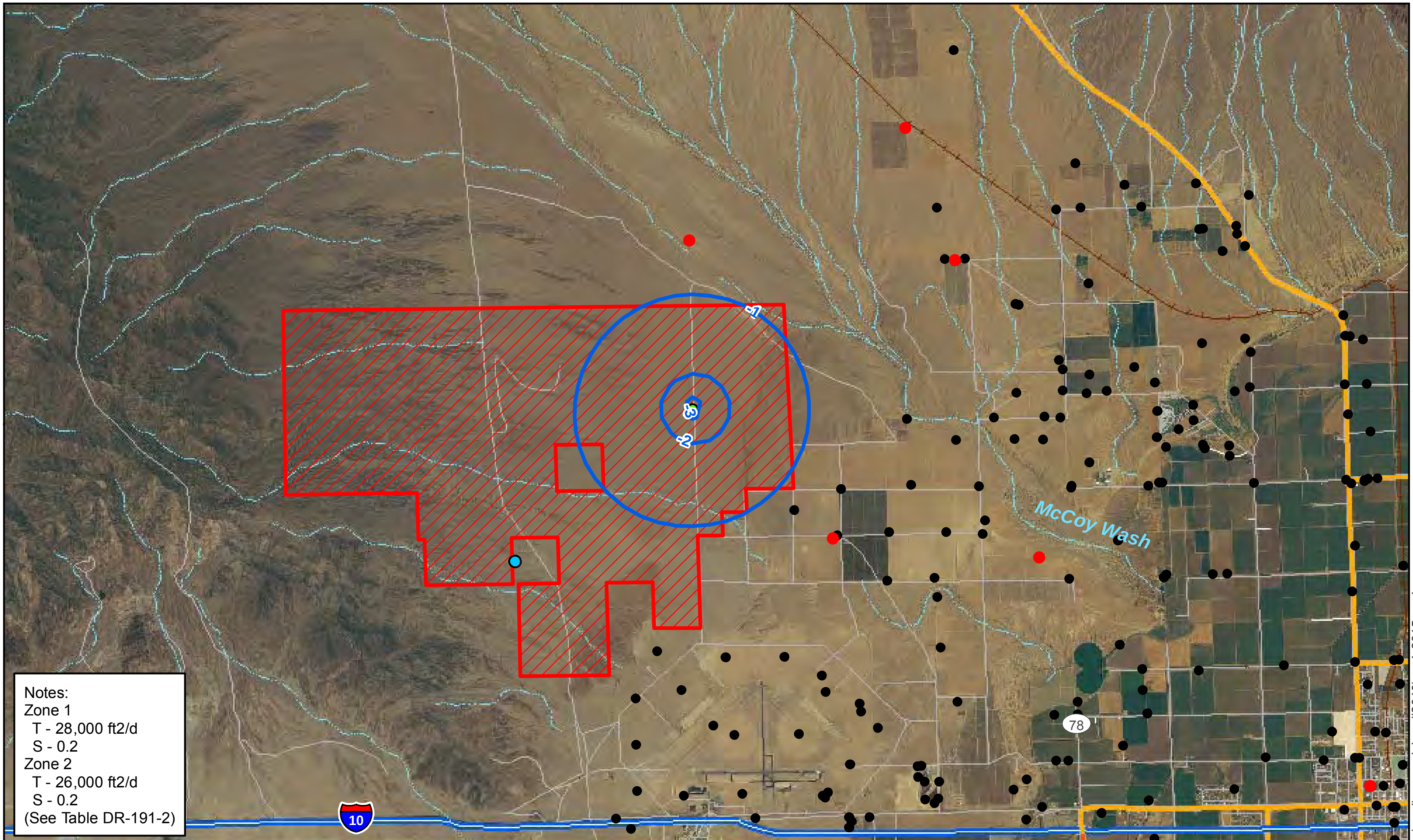

Map Location

Legend

- Contours of Drawdown (feet)
- Groundwater Wells Identified as Potentially Active in AFC
- Groundwater Well Location
- Pumping Well
- Possible Well Location Not Identified in USGS or DWR Database
- Blythe Solar Power Project Right of Way

Data Sources:
Air Photo, NAIP, 2005
Basemap, (Roads, streams, cities), ESRI

1 inch = 8,000 feet

0 6,000 12,000 Feet

N S E W

Blythe Solar Power Project

Soil and Water
Figure 4
Groundwater Modeling of Proposed Project Pumping
Run 2
Year 2015-End of Construction

Palo Verde I, LLC

AECOM

Project: 60139695
Date: April 2010

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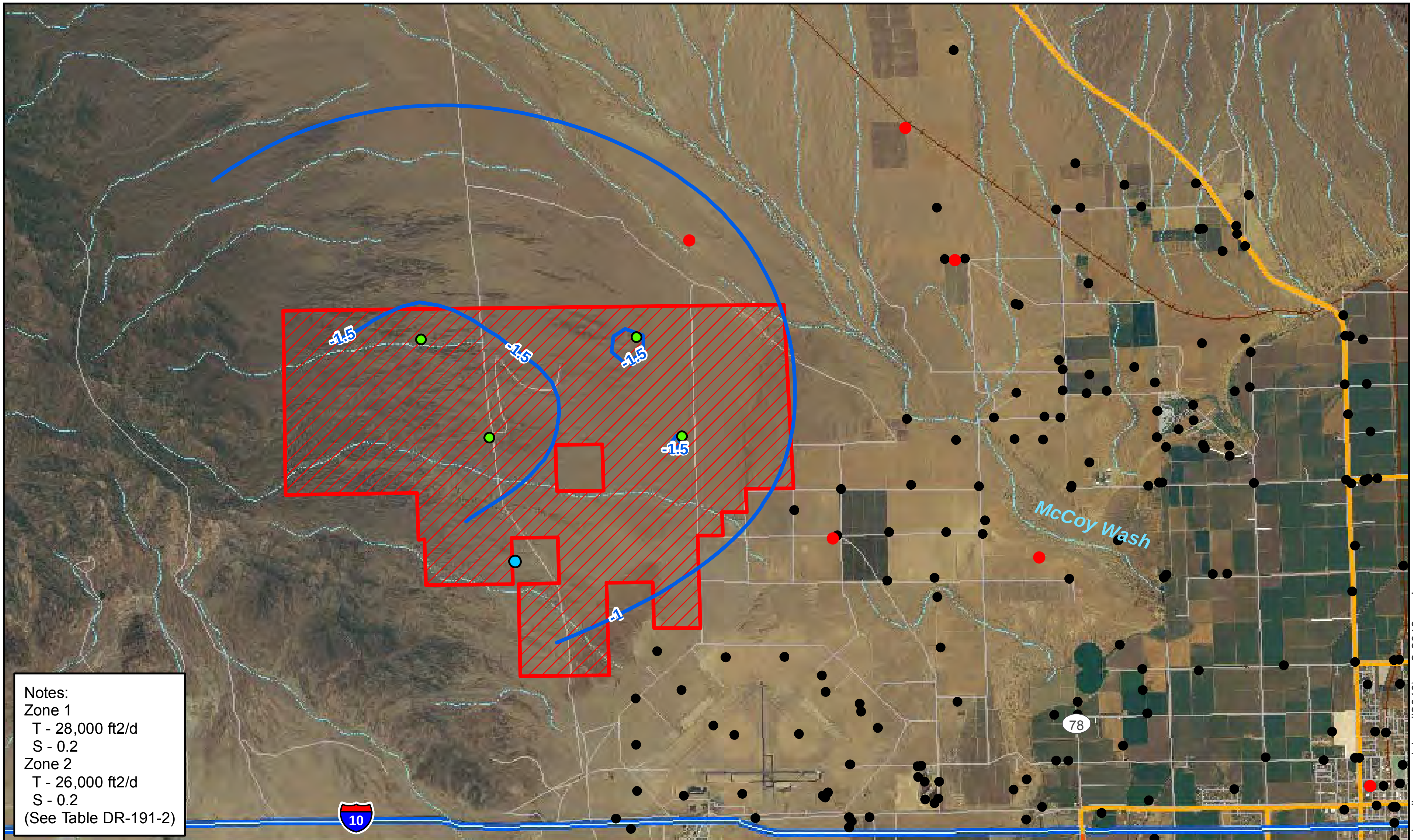

Map Location

Legend

- Contours of Drawdown (feet)
- Groundwater Wells Identified as Potentially Active in AFC
- Groundwater Well Location
- Pumping Well
- Possible Well Location Not Identified in USGS or DWR Database
- Blythe Solar Power Project Right of Way

0 6,000 12,000 Feet

1 inch = 8,000 feet

Data Sources:
Air Photo, NAIP, 2005
Basemap, (Roads, streams, cities), ESRI

Blythe Solar Power Project

Soil and Water
Figure 5
Groundwater Modeling of Proposed Project Pumping
Run 2
Year 2043-End of Operations

Palo Verde I, LLC

AECOM

Project: 60139695
Date: April 2010

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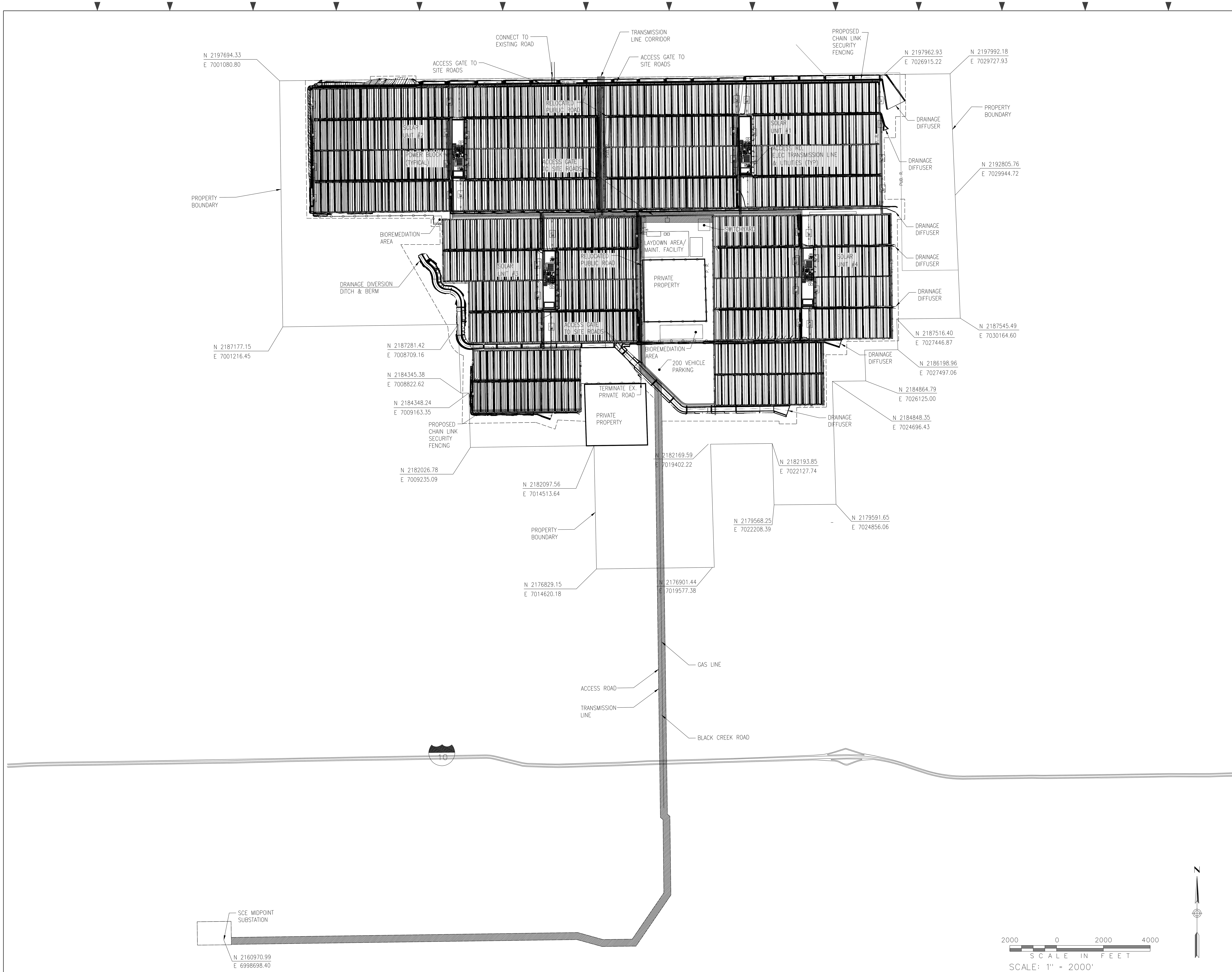


– PRELIMINARY –
NOT FOR CONSTRUCTION

REV	DESCRIPTION	DWN	CHK	APP	DATE
F	ADDED NORTHERN/SWITCHYARD TRANSMISSION LINE CORRIDORS	BAS			04-02-10
E	UPDATED DISTURBANCE AREA PER AECOM REQUEST	SMC			03-02-10
D	UPDATED GAS AND TRANSMISSION LINE LOCATION	SMC			02-17-10
C	NEW GAS LINE LOCATION	SMC			02-02-10
B	NEW TRANSMISSION LINE LOCATION	SMC			01-29-10
A	ISSUED FOR REVIEW	SMC			12-31-09

KIEWIT/MAN SOLAR MILLENNIUM

240 MW SOLAR ENERGY CENTER

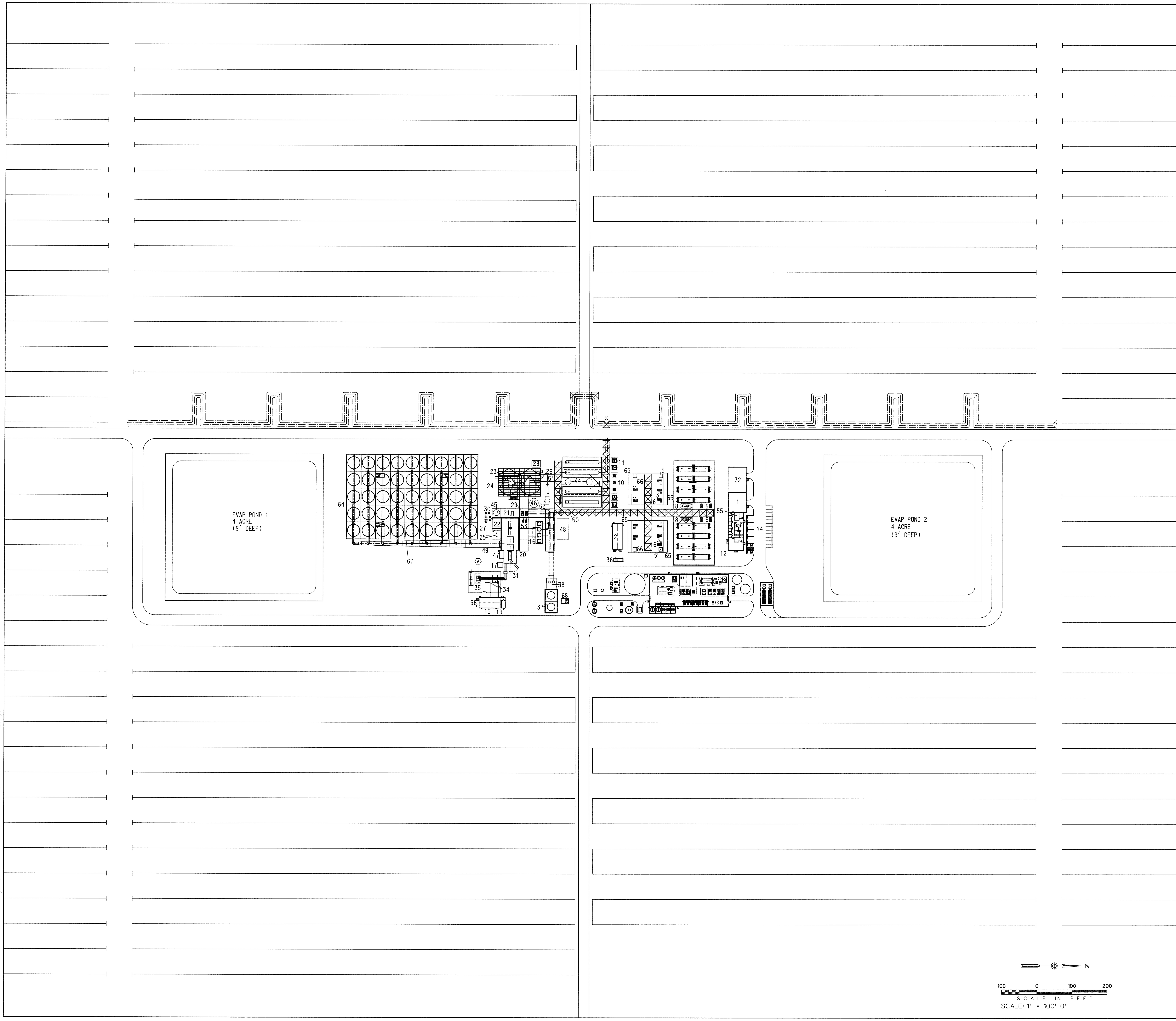
Kiewit

Kiewit Power
9401 Renner Boulevard
Lenexa, Kansas 66219

SITE PLAN AND BOUNDARY

	by	date
DESIGNED	BAS	12-29-09
DRAWN	SMC	12-30-09
CHECKED		
APPROVED		

DRAWING NUMBER
2008-045-CS-001



DRAWING LEGEND

1. WORKSHOP BUILDING
2. HTF EQUIPMENT MCC'S
3. VARIABLE FREQUENCY DRIVE SYSTEM
4. STEAM GENERATORS
5. HTF PUMPS SEAL OIL UNIT
6. HTF MAIN PUMPS
7. NOT USED
8. OVER FLOW AND EXPANSION VESSELS
9. OVER FLOW RETURN PUMPS
10. ULLAGE COOLERS AND VESSEL
11. NITROGEN SYSTEM
12. WEATHER STATION
13. NOT USED
14. PARKING
15. BALANCE OF PLANT ELECTRICAL
16. REHEATERS
17. EXCITATION TRANSFORMER
18. WATER TREATMENT MCCS (SEE GA-003ALT)
19. COOLING TOWER MCC
20. STEAM TURBINE
21. GLAND CONDENSER
22. LUBE OIL CONSOLE
23. DEAERATOR (ON STRUCTURE)
24. FEEDWATER PUMPS (UNDER STRUCTURES)
25. CONDENSATE PUMPS
26. LP/HP FW HEATERS (ON STRUCTURE)
27. VACUUM SYSTEM
28. DIRTY WASTEWATER SUMP, OIL WATER SEPARATOR
29. AUXILIARY COOLING WATER HEAT EXCHANGERS
30. COMPRESSED AIR SYSTEM
31. GENERATOR CIRCUIT BREAKER
32. WAREHOUSE
33. NOT USED
34. MAIN AUXILIARY TRANSFORMERS
35. GENERATOR STEP-UP TRANSFORMER
36. EMERGENCY DIESEL GENERATOR
37. COOLING TOWER
38. CIRCULATING WATER PUMPS
39. FIRE AND SERVICE WATER TANK (SEE GA-003ALT)
40. SERVICE WATER PUMPS (SEE GA-003ALT)
41. NOT USED
42. FIRE PROTECTION PUMPS (SEE GA-003ALT)
43. NOT USED
44. BLOWDOWN TANKS
45. TURBINE DRAINS TANK
46. CONDENSATE DRAINS TANK
47. STG PEECC
48. AUXILIARY BOILER
49. ACC STEAM DUCT
50. HTF PIPING CONNECTION TO SOLAR FIELD
51. SAMPLE PANEL & LAB BUILDING
52. DEMINERALIZED WATER TANK (SEE GA-003ALT)
53. CLOSED CYCLE COOLING WATER PUMPS
54. WATER TREATMENT AREA (SEE GA-003ALT)
55. ADMINISTRATION BUILDING
56. NOT USED
57. NOT USED
58. SUS TRANSFORMER & 480 V BUS
59. DEMINERALIZED WATER PUMPS (SEE GA-003ALT)
60. PIPE RACK
61. NOT USED
62. CHEMICAL FEED CANOPY
63. NOT USED
64. AIR COOLED CONDENSER (ACC)
65. HTF SWITCHYARD
66. HTF PUMPS LUBE OIL UNIT
67. MCC ACCS
68. COOLING TOWER CHEM FEED BUILDING

INTERCONNECT LIST

A HV ELECTRICAL - HIGH SIDE TERMINALS OF GSU

- PRELIMINARY -
NOT FOR CONSTRUCTION

CONFIDENTIAL

REV	DESCRIPTION	DWN	CHK	APP	DATE
F	ADDED CT CHEM FEED BLDG; REVISED ACC, ADDED WASTEWATER RECOVERY SYSTEM	SRH	RT	SJL	04-15-10
E	ROTATED STG STEP UP TRANSFORMER AND SHIFTED POWER BLOCK 25'-0" SOUTH, DELETED ITEM 7, 13, 41, 56, 57 AND SIZES FOR INTERCONNECT B & C,	CED	SMG	DES	04-02-10
D	ADDED CT CHEM FEED BUILDING; REVISED ACC	SRH	SMG	DES	11-04-09
C	PRELIMINARY	SRH	SMG	DES	08-10-09
B	PRELIMINARY	SRH	SMG	DES	07-28-09
A	PRELIMINARY	SRH	SMG	DES	07-09-09

KIEWIT-MSM JOINT VENTURE

SOLAR MILLENNIUM

BLYTHE SOLAR POWER PLANT

Kiewit

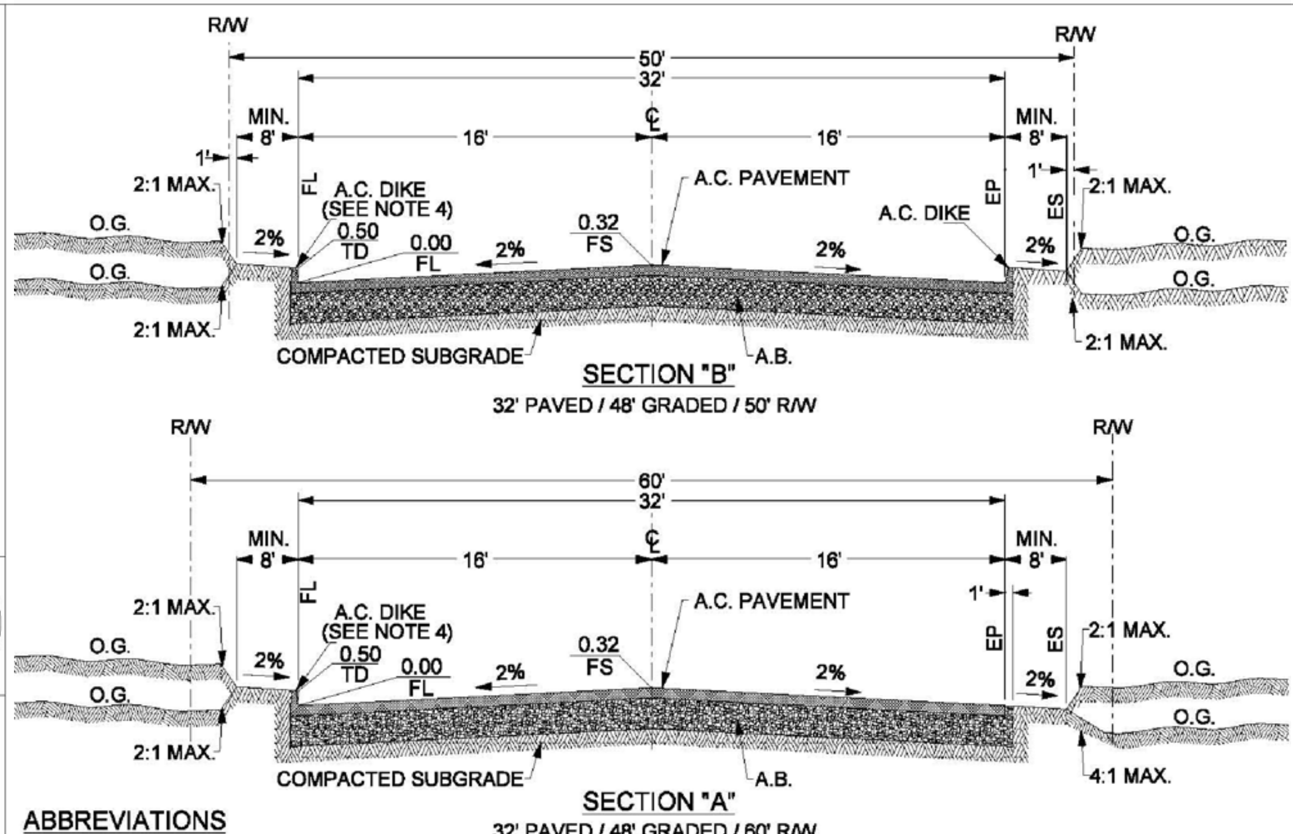
Kiewit Power
8455 Lenexa Drive
Lenexa, Kansas 66214

PLOT PLAN
AIR COOLED CONDENSER OPTION

	by	date
DESIGNED	DES	06-26-09
DRAWN	SRH	06-26-09
CHECKED		
APPROVED		

DRAWING NUMBER

2008-045E-PP-001ALT



ABBREVIATIONS

A.B. = AGGREGATE BASE
A.C. = ASPHALT CONCRETE
C&G = CURB AND GUTTER
EP = EDGE OF PAVEMENT
ES = EDGE OF SHOULDER
FL = FLOW LINE
O.G. = ORIGINAL GROUND
R/W = RIGHT OF WAY
TD = TOP OF DIKE
FS = FINISHED SURFACE

NOTE:

1. THICKNESS OF A.B. AND A.C. TO BE DETERMINED BY SOIL TEST AT TIME OF GRADING OPERATIONS.
2. MINIMUM PAVING THICKNESS PER SPECIFICATIONS SECTION 8.07 OF THIS ORDINANCE.
3. SEE STANDARD NO. 212 FOR A.C. DIKE DETAIL.
4. FOR ACCESS ROAD A.C. DIKE ONLY REQUIRED WHEN NECESSARY TO CONTROL DRAINAGE. DIKE MAY BE REQUIRED ON ONE OR BOTH SIDES.

APPROVED BY:

DIRECTOR OF TRANSPORTATION
GEORGE A. JOHNSON, RCE 42328

DATE: 05/01/07

REVISIONS	REV.	BY:	APPR'D	DATE	REV.	BY:	APPR'D	DATE
8-71, 11-80	1				4			
10-81, 6-82	2				5			
12-87, 11-04	3				6			

GEORGE A. JOHNSON
No. CE 42328
Exp. 3-31-08
CIVIL
STATE OF CALIFORNIA
REGISTERED PROFESSIONAL ENGINEER

COUNTY OF RIVERSIDE

OFFSITE ACCESS ROAD (60' R/W)

STANDARD NO. 106

Map Location

Blythe Solar Power Project

Access Road Cross Section
Figure 1 Road-1
Riverside County
Road Specifications

Palo Verde I, LLC

AECOM

Project: 60139695
Date: April 2010

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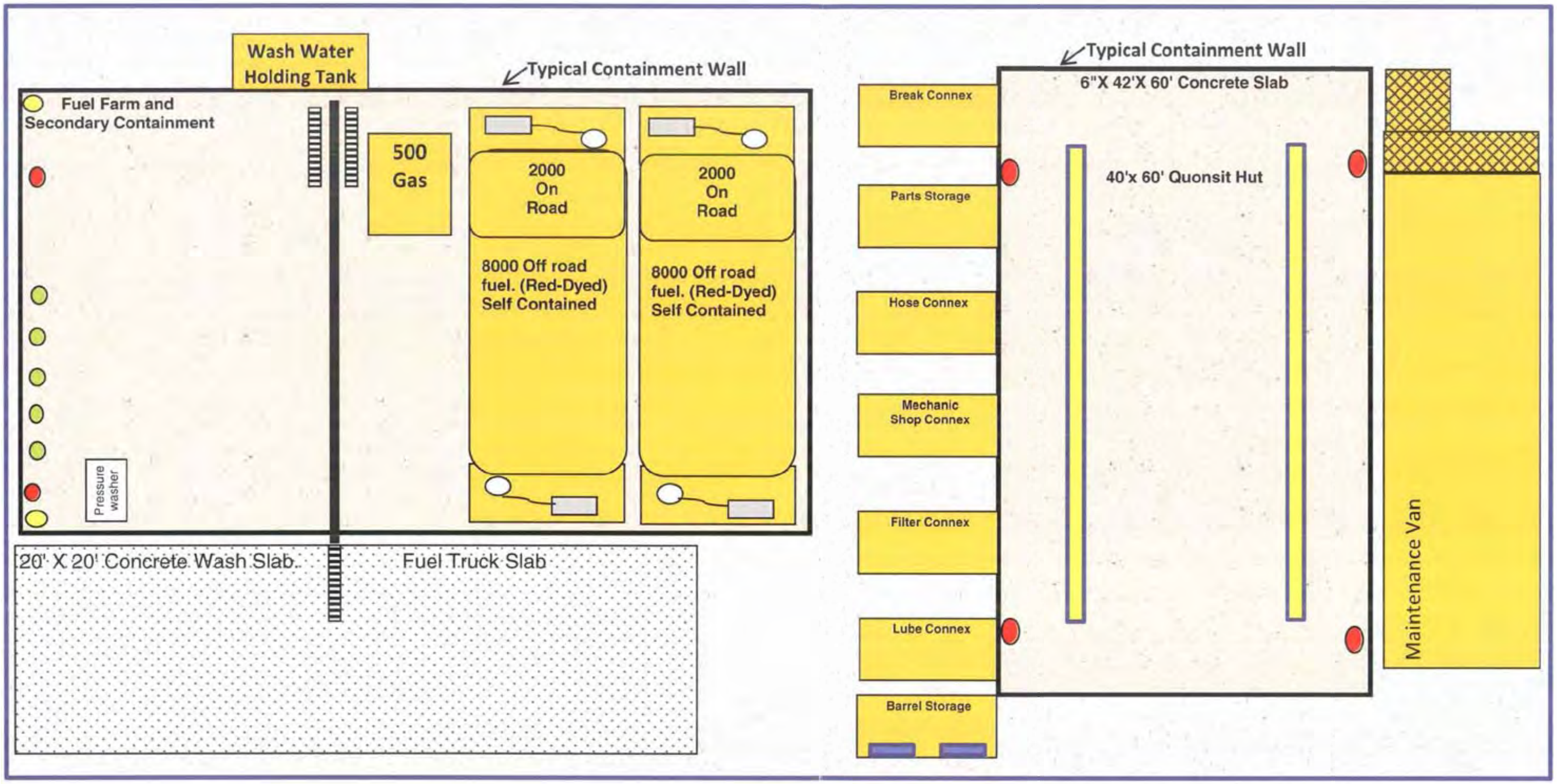

Map Location

Blythe Solar Power Project

Figure 1 Depot-1
Fuel Depot Layout

Palo Verde I, LLC

AECOM

Project: 60139695
Date: April 2010

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Table Air 1 Revised Boiler Hours of Operation

Function	Maximum Daily Operation	Maximum Annual Operation
Start up Support	2 hours at 100% load	500 hours at 100% load
HTF Freeze Protection	10 hours at 100% load	100 hours at 100% load
Standby	15 hours at 25% load	4,500 hours at 25% load
Total 17	hours (12 at 100% and 5 at 25%)	5,100 hours

Table Air 2 Revised Boiler Emissions (One Boiler)

Pollutant	Emissions		
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Annual Emissions (ton/yr)
NOx 0.389		5.152	0.335
VOC 0.175		2.319	0.151
CO 1.315		17.421	1.134
PM10 0.350		4.638	0.302
PM2.5 0.350		4.638	0.302
SOx 0.010		0.126	0.008

Table Air 3 Concrete Batch Plant Emissions

Source	Maximum Hourly Emissions				
	NOx	VOC	CO	SOx	PM10
	(lb/hr)				
Batch Plant	---	---	---	---	0.029
Storage Piles	---	---	---	---	0.020
Generator	0.591	0.040	0.699	0.002	0.031
Front End Loader	1.195	0.089	0.284	0.002	0.031
Total	**1.79**	**0.13**	**0.98**	**0.00**	**0.110**
Source	**Daily Emissions**				
	NOx	**VOC**	**CO**	**SOx**	**PM10**
	(lb/day)				
Batch Plant	---	---	---	---	0.29
Storage Piles	---	---	---	---	0.47
Generator	5.91	0.40	6.99	0.02	0.31
Front End Loader	11.95	0.89	2.84	0.02	0.31
Total	**17.86**	**1.30**	**9.84**	**0.03**	**1.38**
Source	**Annual Emissions**				
	NOx	**VOC**	**CO**	**SOx**	**PM10**
	(ton/yr)				
Batch Plant	---	---	---	---	0.052
Storage Piles	---	---	---	---	0.085
Generator	0.709	0.048	0.839	0.002	0.037
Front End Loader	1.434	0.107	0.341	0.002	0.038
Total	**2.143**	**0.155**	**1.180**	**0.004**	**0.211**

TABLE SOIL and WATER 5.17-10
CUMULATIVE IMPACTS ASSESSMENT
ESTIMATE OF BASINWIDE WATER LEVEL CHANGE
PALO VERDE GROUNDWATER BASIN
RIVERSIDE COUNTY, CALIFORNIA

PROJECT[1]	PROPONENT	BLM SERIAL ID	TECHNOLOGY	SOURCE	USE	WATER USE - SOLAR and OTHER RENEWABLE PROJECTS (af)															COMMENTS
						2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2043	
Big Maria Vista Solar Project	Bullfrog Green Energy, LLC	CA 49702	Photovoltaic (500MW)	Assumed to be Groundwater	Construction	--	8	7	7	--	--	--	--	--	--	--	--	--	--	--	Operation water use given as 6,000 gal/month (0.22 afy). No construction water use provided in POD; assume total 22 af over three years construction.
					Operational	--	--	--	--	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	
Blythe Airport Solar 1	US Solar	--	Photovoltaic (100MW)	Though not stated, assumed either groundwater or water trucked in from an offsite source	Construction	--	1.6	1.6	--	--	--	--	--	--	--	--	--	--	--	--	No water usage given in POD. Assume water usage to be 20% of water usage for similar PV project (Big Maria Vista).
					Operational	--	--	--	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	
Blythe Energy Project II	Blythe Energy, LLC	--	Combined/Cycle (520MW)	Groundwater	Construction	--	60	60	--	--	--	--	--	--	--	--	--	--	--	--	AFC (2004) indicates construction to last up to 22 months (76 acres) - no volume specified; Operational usage of 3,300 afy. Assume construction water usage 60 gal/cy. Further, assume grading encompasses entire site (76 acres) to an average depth of 5 feet (~620,000 cy).
					Operational	--	--	--	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	
Blythe PV Project	First Solar	--	Photovoltaic (7.5 MW)	Though not stated, assumed either groundwater or water trucked in from an offsite source	Construction	--	0.1	0.1	--	--	--	--	--	--	--	--	--	--	--	--	Assumes 24 month construction period. No water amount specified. Given small output, assume minimal water usage for construction and operational use.
					Operational	--	--	--	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
Blythe Solar Power Project	Solar Millennium LLC	CA 48811	Parabolic Trough (484MW)	Groundwater	Construction		820	820	820	820	820		--	--	--	--	--	--	--	--	POD assumes 69 month (5.75 years) construction period with total water usage during construction to be 3,100 af and 600 afy usage during operational phase. Construction water usage averaged over a period of 5 years starting in 2011 (proposed construction start is 4th quarter 2011).
					Operational	--	--	--	150	300	450	600	600	600	600	600	600	600	600	600	
Desert Quartzite Solar Farm	First Solar (formerly OptiSolar)	CA 49377	Photovoltaic (601MW)	Though not stated, assumed either groundwater or water trucked in from an offsite source	Construction	2	7	7	7	4	--	--	--	--	--	--	--	--	--	--	POD assumes construction period beginning mid-2010 with facility startup in 2013 or 2014. Assumes 27 af total water for construction and 3.8 afy for operational use thereafter.
					Operational	--	--	--	--	3	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	
McCoy Soleil Project	enXco	CA 49490	Photo Tower (136MW)	Groundwater	Construction	--	1000	150	75	--	--	--	--	--	--	--	--	--	--	--	POD assumes 30-month construction period with facility startup at end of 2013. Assumes water use of 1,225 af over total construction period and 600 afy for operational use thereafter.
					Operational	--	--	--	75	600	600	600	600	600	600	600	600	600	600	600	
Mule Mountain Solar Project	Bullfrog Green Energy, LLC (acquired by Altera)	CA 49097	Photovoltaic (500MW)	Though not stated, assumed either groundwater or water trucked in from an offsite source	Construction	--	8	7	7	--	--	--	--	--	--	--	--	--	--		Construction & operational supply not specified in the POD. Assumed to be same as other proposed PV projects. Three phases - operational water use estimated at 6,000 gal/mo/phase.
					Operational	--	--	--	--	0..22	0..22	0..22	0..22	0..22	0..22	0..22	0..22	0..22	0..22	0.22	
TOTAL WATER USE - RENEWABLE PROJECTS (af)[2]						**2**	**1,905**	**1,053**	**4,441**	**5,027**	**5,174**	**4,504**	**4,504**	**4,504**	**4,504**	**4,504**	**4,504**	**4,504**	**4,504**	**4,504**	
CUMULATIVE CHANGE (af)[3]						**2**	**1,907**	**2,959**	**7,400**	**12,428**	**17,602**	**22,106**	**26,610**	**31,114**	**35,618**	**40,122**	**44,626**	**49,130**	**53,634**	**143,716**	
MESA INFLOW						**10,346**	**10,346**	**10,346**	**10,346**	**10,346**	**10,346**	**10,346**	**10,346**	**10,346**	**10,346**	**10,346**	**10,346**	**10,346**	**10,346**	**10,346**	
MESA OUTFLOW						**8,992**	**8,992**	**8,992**	**8,992**	**8,992**	**8,992**	**8,992**	**8,992**	**8,992**	**8,992**	**8,992**	**8,992**	**8,992**	**8,992**	**8,992**	
MESA WATER BALANCE						**1,352**	**-551**	**301**	**-3,087**	**-3,673**	**-3,820**	**-3,150**	**-3,150**	**-3,150**	**-3,150**	**-3,150**	**-3,150**	**-3,150**	**-3,150**	**-3,150**	
CHANGE IN REGIONAL WATER LEVEL ON THE MESA (assuming a storage coefficient of 0.20)(inches)[4]						**-0.0007**	**-1**	**-1**	**-2**	**-4**	**-6**	**-7**	**-9**	**-10**	**-12**	**-13**	**-15**	**-16**	**-17**	**-47**	
CHANGE IN REGIONAL WATER LEVEL ON THE MESA (assuming a storage coefficient of 0.05)(inches)[4]						**-0.0026**	**-2**	**-4**	**-10**	**-16**	**-23**	**-29**	**-35**	**-41**	**-46**	**-52**	**-58**	**-64**	**-70**	**-187**	
PERCENTAGE RENEWABLE PROJECT CUMULATIVE WATER USE BY COMPARISON TO ESTIMATED TOTAL STORAGE (5M af - DWR 2004)						**--**	**0.04%**	**0.06%**	**0.15%**	**0.25%**	**0.35%**	**0.44%**	**0.53%**	**0.62%**	**0.71%**	**0.80%**	**0.89%**	**0.98%**	**1.07%**	**2.87%**	
PERCENT BSPP USAGE BY COMPARISON TO YEARLY TOTAL RENEWABLE WATER USAGE						**--**	**43%**	**78%**	**18%**	**16%**	**16%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	

NOTES

1 Project descriptions provided in Section 5.1 (Table 5.1.2) of the AFC.
2 Sum of renewable projected water use by year for the identified renewable energy projects.
3 Cumulative change is a sum adding the prior years water use to the current water year for each year beginning in 2010 and ending in 2043.
4 Estimated change in the regional water level following the equation shown below (Fetter 1988). Negative values indicate a decline in water levels.

DEFINITIONS

afy acre feet per year
af acre feet - (325,829 gallons)
LLC Limited Liability Corporation
MW Megawatts
POD Plan of Development
-- No information available in referenced doucmnet

ESTIMATE OF BASINWIDE WATER LEVEL CHANGE

V = A*S*dh V - volume of water released or taken into storage (acre-feet)
A - area of the aquifer (226,000 acres)
S- aquifer storage (assumed to be 0.10)
dh - change in water level (inches)

TABLE
SOIL and WATER-191-1 (rev1)
PUMPING SCHEDULE FOR NUMERICAL GROUNDWATER MODELING
PROJECT REVISION
CHANGE OF CONSTRUCTION WATER VOLUME TO 4100 ACRE-FEET
BLYTHE SOLAR POWER PROJECT

PROPONENT	BLM SERIAL ID	TECHNOLOGY	SOURCE	USE	WATER USE - SOLAR and OTHER RENEWABLE PROJECTS (af)							COMMENTS
					2010	2011	2012	2013	2014	2015	2015-2043	
Bullfrog Green Energy, LLC	CA 49702	Photovoltaic (500MW)	Groundwater	Construction	--	8	7	7	--	--	**--**	Operation water use given as 6,000 gal/month (0.22 afy). No construction water use provided in POD; assume total 22 af over three years construction.
				Operational	--	--	--	--	0.22	0.22	**0.22**	
US Solar	--	Photovoltaic (100MW)	Groundwater	Construction	--	1.6	1.6	--	--	--	**--**	No water usage given in POD. Assume water usage to be 20% of water usage for similar PV project (Big Maria Vista).
				Operational	--	--	--	0.04	0.04	0.04	**0.04**	
Blythe Energy, LLC	--	Combined/Cycle (520MW)	Groundwater	Construction	--	60	60	--	--	--	**--**	AFC (2004) indicates construction to last up to 22 months (76 acres) - no volume specified; Operational usage of 3,300 afy. Assume construction water usage 60 gal/cy. Further, assume grading encompasses entire site (76 acres) to an average depth of 5 feet (~620,000 cy).
				Operational	--	--	--	3,300	3,300	3,300	**3,300**	
First Solar	--	Photovoltaic (7.5 MW)	Groundwater	Construction	--	0.1	0.1	--	--	--	**--**	Assumes 24 month construction period. No water amount specified. Given small output, assume minimal water usage for construction and operational use.
				Operational	--	--	--	0.01	0.01	0.01	**0.01**	
First Solar (formerly OptiSolar)	CA 49377	Photovoltaic (601MW)	Groundwater	Construction	2	7	7	7	4	--	**--**	POD assumes construction period beginning mid-2010 with facility startup in 2013 or 2014. Assumes 27 af total water for construction and 3.8 afy for operational use thereafter.
				Operational	--	--	--	--	3	3.8	**3.8**	
enXco	CA 49490	Photo Tower (136MW)	Groundwater	Construction	--	1000	150	75	--	--	**--**	POD assumes 30-month construction period with facility startup at end of 2013. Assumes water use of 1,225 af over total construction period and 600 afy for operational use thereafter.
				Operational	--	--	--	75	600	600	**600**	
Solar Millennium LLC **Data Response January 2010**	CA 48811	Parabolic Trough (484MW)	Groundwater	Construction		620	620	620	620	620	**--**	POD assumes 69 month (5.75 years) construction period with total water usage during construction to be **3,100 af** and 600 afy usage during operational phase. Construction water usage averaged over a period of 5 years starting in 2011.
				Operational	--	--		150	300	450	**600**	
Solar Millennium LLC Project Revision **April 2010**	CA 48811	Parabolic Trough (484MW)	Groundwater	Construction		820	820	820	820	820	**--**	POD assumes 69 month (5.75 years) construction period with total water usage during construction to be **4,100 af** and 600 afy usage during operational phase. Construction water usage averaged over a period of 5 years starting in 2011.
				Operational	--	--		150	300	450	**600**	

TABLE
SOIL and WATER 191-2 (rev1)
RESULTS OF NUMERICAL MODELING
PROJECT REVISION
CONSTRUCTION WATER VOLUME CHANGE TO 4100 ACRE-FEET
BLYTHE SOLAR POWER PROJECT

Model Scenario[1]	Zone 1		Zone 2		Year	CONSTRUCTION PUMPING (TW-1)			OPERATIONAL WELLS (SEE FIGURE 1)[4]				Storage change	Storage Change[2]	Water level change[3]	Objective
	T	S	T	S		Drawdown feet	Distance to 1 ft contour	Distance to 5 ft contour	WELL NO.1 Drawdown	WELL NO.2 Drawdown	WELL NO.3 Drawdown	WELL NO. 4 Drawdown	Acre-ft	% of Recoverable	feet	
Run 1	10,000	0.2	6,300	0.2	2015	18.327	10190	1510	--	--	--	--	4,992	0.10%	0.11	Project only impacts assessment using only the single well on the Project site for construction and four well (one in each Power Block for operation). Pumping follows schedule shown on Table DR Soil and Water-191-1. Results shown on Figure 2 and 3.
					2029	--	--	--	4.132	3.897	4.375	3.801	13,355	0.27%	0.30	
					2043	--	--	--	4.985	4.564	5.196	4.436	21,173	0.42%	0.47	
Run 2	28,000	0.2	26,000	0.2	2015	6.984	6984	60	--	--	--	--	4,948	0.10%	0.11	Project only impacts assessment using only the single well on the Project site for construction and four well (one in each Power Block for operation). Pumping follows schedule shown on Table DR Soil and Water-191-1. Results shown on Figure 2 and 3.
					2029	--	--	--	1.602	1.656	1.653	1.599	12,539	0.25%	0.28	
					2043	--	--	--	1.851	1.882	1.883	1.806	19,439	0.39%	0.43	

Notes
1 The pumping schedule for the water supply well onsite and those used for the cumulative impacts analysis are provided in Table DR Soil and Water-191-1
2 The storage change is based on a recoverable storage of 5,000,000 acre-feet as reported by the DWR (2004)
3 Estimate of basin-wide water level change after Fetter (1988):
4 The extent of pumping influence is shown on Figures 2 through 5 for Run 1 and Run 2.

$V = A*S*dh$

V - volume of water released or taken into storage
A - area of the aquifer (353 square miles)
S- aquifer storage (assumed to be 0.20)
dh - change in water level (inches)

Table Air 4 Revised Emissions for One Cooling Tower Unit

Pollutant	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Annual Emissions (ton/yr)
PM10	0.030 0.725	0.132	
PM2.5	0.030 0.725	0.132	

Table Air 5 Revised Maintenance Vehicle Emissions for the BSPP

Vehicle	NOx	VOC	CO	SOx	Exh. PM10	Fug. PM10	Diesel PM	Exh. PM2.5	Fug. PM2.5
	Maximum Hourly Emissions								
	(lb/hr)								
Mirror Wash Truck	0.176	0.018	0.089	0.002	0.005	48.256	0.005	0.005	4.827
Soil Stabilizer Application	0.052	0.005	0.026	0.001	0.001	14.243	0.001	0.001	1.425
Weed Abatement	0.052	0.005	0.026	0.001	0.001	14.243	0.001	0.001	1.425
Maintenance Vehicles	0.001	0.000	0.013	0.000	0.000	12.240	---	0.000	1.224
Total	**0.28**	**0.03**	**0.16**	**0.00**	**0.008**	**88.98**	**0.01**	**0.007**	**8.90**
Vehicle	**Daily Emissions**								
	NOx	**VOC**	**CO**	**SOx**	**Exh. PM10**	**Fug. PM10**	**Diesel PM**	**Exh. PM2.5**	**Fug. PM2.5**
	(lb/day)								
Mirror Wash Truck	1.40	0.14	0.72	0.01	0.04	386.05	0.04	0.04	38.62
Soil Stabilizer Application	0.41	0.04	0.21	0.00	0.01	113.94	0.01	0.01	11.40
Weed Abatement	0.41	0.04	0.21	0.00	0.01	113.94	0.01	0.01	11.40
Maintenance Vehicles	0.02	0.01	0.21	0.00	0.00	195.84	---	0.00	19.59
Total	**2.25**	**0.23**	**1.34**	**0.02**	**0.07**	**809.77**	**0.06**	**0.06**	**81.00**
Vehicle	**Annual Emissions**								
	NOx	**VOC**	**CO**	**SOx**	**Exh. PM10**	**Fug. PM10**	**Diesel PM**	**Exh. PM2.5**	**Fug. PM2.5**
	(ton/yr)								
Mirror Wash Truck	0.164	0.017	0.084	0.002	0.005	45.168	0.005	0.004	4.518
Soil Stabilizer Application	0.049	0.005	0.025	0.000	0.001	13.443	0.001	0.001	1.345
Weed Abatement	0.005	0.001	0.003	0.000	0.000	1.370	0.000	0.000	0.137
Maintenance Vehicles	0.003	0.001	0.035	0.000	0.000	12.705	---	0.000	1.271
Total	**0.221**	**0.023**	**0.147**	**0.002**	**0.007**	**72.685**	**0.006**	**0.006**	**7.271**

Table Air 6 VOC Emissions from Paving Black Rock Road

Item	Units	Quantity
Roadway Area to be Paved	Acres	2.7
Paving Rate	Acres/hr	2.8
Emission Factor	lb/acre	2.6
Hourly VOC Emissions	lb/hour	7.2
Daily VOC Emissions	lb/day	7.2

Table Air 7 Fuel Depot VOC Emissions

Storage Tank	Tank Throughput Gal/yr	VOC Emissions		
		Lbs/hr	**Lbs/day**	**Tons/yr**
Construction				
Diesel Tank 1	1,446,945	0.0025	0.0593	0.0108
Diesel Tank 2	1,446,945	0.0025	0.0593	0.0108
Gasoline Tank	660,714	0.1410	3.3828	0.6174
Total Construction		**0.1459**	**3.5015**	**0.6390**
Operations				
Diesel Tank 1	25,398	0.0006	0.0134	0.0024
Diesel Tank 2	25,398	0.0006	0.0134	0.0024
Gasoline Tank	3,242	0.0189	0.4542	0.0829
Total Operation		**0.0200**	**0.4809**	**0.0878**

Appendix A

Air Modeling Evaluation

1.0 Introduction

This evaluation outlines the supplemental modeling performed to demonstrate compliance with ambient air quality standards in response to a number of minor Project refinements.

The newest version of the AERMOD model (version 09292) was applied with a 3-year sequential hourly meteorological data set, which is more comprehensive than the one year of meteorological data required under Appendix B of the California Energy Commission's Siting Guidelines (CEC, 2006) for both the updated normal operations and construction modeling. Configuration of the model sources, the meteorological data used, and the receptor grids used in the modeling remain the same as in the original application and are fully documented in Section 5.2 of the Application for Certification (AFC) and not repeated here unless they have been modified as noted herein. The Air Dispersion Modeling Archive is included electronically on a CD as Appendix B to this submittal.

2.0 Revised Modeling of BSPP Project Construction

2.1 Modification to the BSPP Construction Modeling

A number of changes were made in the construction modeling to represent design changes to the construction plan originally included in the AFC. These changes include:

- The addition of a concrete batch plant, with associated sources and emissions, to the Facility. These sources were added to the modeling as described below.
- The updated construction schedule includes work to be performed outside of the 10-hour daily construction period originally proposed for the March through September months and 8-hour daily construction periods from October through February. As a result, the hourly emission factors were updated for a number of the construction sources to represent nighttime[2] construction.

The detailed emission calculations for the Batch Plant are provided in the spreadsheet: *Blythe Concrete Batch Plant Emissions.xlsx* on the CD in Appendix C of this submittal.

2.2 Concrete Batch Plant

Because of the remoteness of existing cement production facilities in the area, the updated construction plan includes the use of a temporary concrete batch plant at the Project Site. The facility includes a cement production silo along with a conveyor that runs from aggregate bins up to the load chute of the mixer. Emissions include fugitive emissions from aggregate transfer along with combustion (i.e., tailpipe) and entrained road dust (respirable particulate matter [PM10]) emissions from front-loaders moving aggregate from piles to the bins for processing into cement. Additionally, the batch plant includes a generator to supply power for the cement production process.

Two sources were added to the construction modeling to represent the concrete batch plant. The first was an area source of 100 feet by 100 feet, (30.5 square meters) with parameters identical to the fugitive sources representing the other aspects of construction. A release height of 2.0 meters was assumed for the fugitive source, with an initial plume height of 15 feet (4.57 meters). Following

[2] In this evaluation, "nighttime" is used to mean all hours outside of the daylight construction hours discussed in the AFC. Specifically, for the period of March through September, nighttime refers to those hours between 5:00 P.M. and 7:00 A.M., and for the period of October through February, nighttime refers to those hours between 4:00 P.M. and 8:00 A.M.

U.S. Environmental Protection Agency (EPA) AERMOD guidance (EPA 2004), the initial area source vertical standard deviation for construction combustion emissions is estimated as the plume depth divided by 2.15, or 2.13 meters.

The second source added for the batch plant was a point source representing the batch plant generator. This source was placed at the center of the batch plant area with source parameters as shown in Table 2-1. Because there will be no solid permanent structures located on site in the vicinity of the batch plant during construction, no Good Engineering Practice (GEP) analysis to assess building downwash was performed for the generator. There are a number of possible locations for the concrete batch plant over the course of the Project construction. For the modeling, the sources were placed along the access road to the south of Power Block #2 to maximize the overlap of impacts with other construction sources in order to model the most conservative construction case as discussed in the AFC Section 5.2. The modeled location of the concrete batch plant and all short-term modeling sources is shown in Figure 2-1.

Table 2-1: Batch Plant Generator Source Parameters.

Parameter	Value
Stack Height (feet)	23
Stack Diameter (feet)	0.75
Exit Temperature (degrees Fahrenheit)	770
Exit Velocity (feet per second)	464.9

2.3 Modifications to the Construction Source Emissions

As described in Section 2.1, the construction schedule will include work beyond the 10 or 8-hour days described in the AFC in both the power block areas of the Facility and the locations where solar panels are being installed. As a result, these nighttime emissions were included in the revised construction modeling. For the short-term modeling, the following sources were assumed to operate during the nighttime hours:

- Solar panel installation sources;
- Power block construction sources; and
- Concrete batch plant sources.

All other construction sources (i.e., the clearing and grubbing, the grading and scraping, and the transportation corridor) are assumed not to operate during nighttime hours.

For the annual modeling, the power block and concrete batch plant sources were assumed to operate and the percentage of the solar field construction sources representing the solar panel installation operations were assumed to operate during the nighttime hours.

2.4 Impacts from BSPP Construction

The results of the revised construction modeling are shown in Table 2-2. As shown in the table, all impacts, when added to the appropriate ambient backgrounds, are below their respective National Ambient Air Quality Standards (NAAQS)/ California Ambient Air Quality Standard (CAAQS) with the exception of 24-hour and annual PM10, 24-hour Particulate Matter less than 2.5 microns (PM2.5), and 1-hour Nitrogen Dioxide (NO_2). Project impacts alone are below their respective CAAQS with maximum concentrations of 43.0 micrograms per cubic meter (μg/m^3) for 24-hour PM10, 3.9 μg/m^3 for annual PM10, and 14.4 μg/m^3 for 24-hour PM2.5.

In the case of PM10 impacts, the maximum modeled 24-hour average and annual mean for PM10 exceed the CAAQS when background concentrations are added because the PM10 air quality monitoring station data used for this Project show that the PM10 CAAQS is already exceeded in the area where the data were collected, i.e., in Niland, California. Actual Project impacts from 24-hour PM10 represent 86 percent of the CAAQS and only 21 percent of the total impact when background is considered. For annual PM10, the Project impacts represent only 19.5 percent of the CAAQS for annual PM10 and only 11.6 percent of the total impact to the annual PM10 concentrations when the worst-case background is considered.

Similarly, for 24-hour PM2.5, the maximum modeled 24-hour average for PM2.5 exceeds the CAAQS when background concentrations are added because the PM2.5 air quality monitoring station data used for this Project is already over the CAAQS before Project impacts are considered. Actual Project impacts from 24-hour PM2.5 represent 41.2 percent of the CAAQS and only 34.8 percent of the total impact when background is considered.

For 1-hour NO_2, a total of 505 hours, or 1.9 percent of the 26,304 hours modeled, indicated impacts which, when added to the maximum ambient background concentration over the most recent 3 years of available data, exceeded the 1-hour NO_2 CAAQS. As an additional refinement, time-matched background data was added to each modeled impact, and the sum compared to the 1-hour NO_2 CAAQS. The results of those added values are shown in Table 2-2. As shown on the table, the maximum modeled concentration of Project impacts plus time matched ambient background is 335.9 μg/m^3, which is below the 1-hour standard of 339 μg/m^3, and thus compliance with the CAAQS is demonstrated.

As was discussed in Section 5.2 of the AFC, identifying appropriate background data for use in this analysis was difficult for the following reasons:

- While the Project Site is in a part of Riverside County designated attainment for PM10, the monitors available are all located to the west in parts of Riverside County or other counties that are designated non-attainment for PM10.
- Additionally, the closest monitors are located in urban/industrial/agricultural areas which are unlikely to fully represent background pollutant concentrations in the Project area.

Table 2-2: NAAQS/CAAQS Analysis for Project Construction

Pollutant	Averaging Period	Concentrations ($\mu g/m^3$)				
		AERMOD Result	Ambient Background[2]	Total [3,4]	CAAQS	NAAQS
NO_2 [1]	1-hr	335.9	N/A	335.9	339	--
	Annual	4.3	22.6	26.9	57	100
CO	1-hr	1068.7	2645	3,714	23,000	40,000
	8-hr	423.6	1,035	1,459	10,000	10,000
PM10	24-hr	43.0	162	205	50	150
	Annual	3.92	30.0	33.9	20	--
PM2.5	24-hr	14.4	27.0	41.4	--	35
	Annual	0.6	10.6	11.2	12	15
SO_2	1-hr	3.4	503.0	506.4	665	--
	3-hr	2.3	434.9	437.2	--	1,300
	24-hr	0.6	99.6	100.1	105	365
	Annual	0.01	5.2	5.2	--	80

[1] Modeled NO_2 concentrations as determined with the OLM. Time-matched ambient background is included in the AERMOD Result for 1-hour NO_2.

[2] From Table 5.2-33 of the BSPP AFC. These values correspond to the highest monitored values from 2005 – 2007, except for PM2.5, which is the 98th percentile value over 3 years for the Indio, California monitoring site.

[3] Modeled concentration plus ambient background.

[4] Result reflects 10-hour days from March through September and 8-hour days from October through February for all sources, with some sources remaining active during night hours as described in Section 2.3

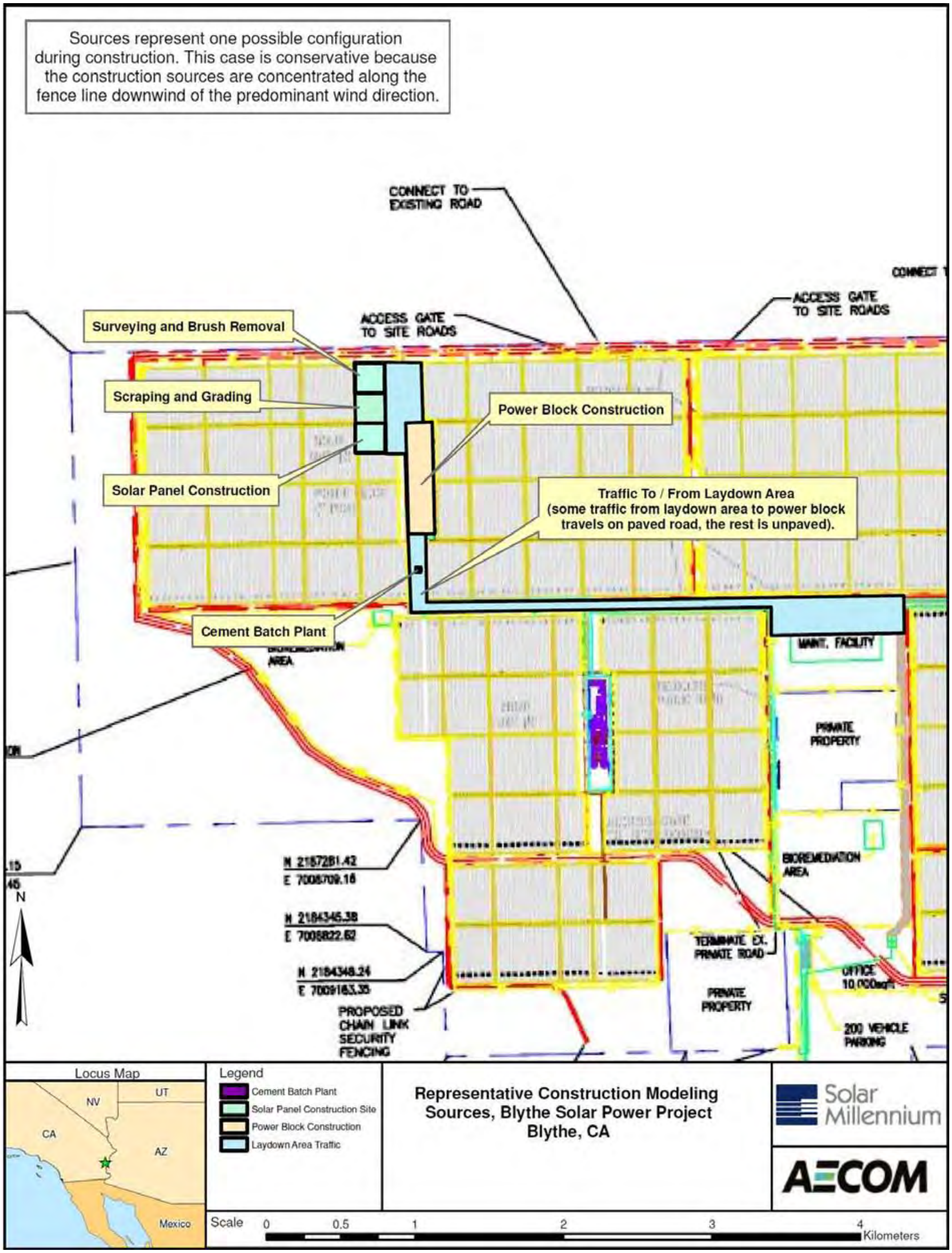

Figure 2-1 Area Sources Used in Short Term Construction Modeling Analysis

3.0 Revised Modeling of BSPP Normal Operations

3.1 Modification to the BSPP Operations Modeling

The following changes were made in the operations modeling to represent design changes to the Site layout and operations emissions originally included in the AFC:

- The Site layout of the power blocks has been revised with new equipment locations. The location of power block sources was revised, and a new GEP analysis to assess building downwash was performed;
- Elimination of the natural gas-fired heat transfer fluid (HTF) heater from the Project operations;
- Increase in the boiler use and hence emissions (as a consequence of the HTF heater removal);
- Increase in hours of operation of the cooling tower;
- Increase in the number of mirror wash events assumed in the air quality impacts analysis;
- Change to the maintenance vehicle travel within the solar field; and
- Elimination of the vehicle travel associated with use of reverse osmosis (RO) concentrate for dust suppression.

Each of these changes is described in more detail below. The revised detailed emission calculations for normal operations are provided in the spreadsheet *Blythe Operation Emissions.xlsx* on the CD in Appendix D of this submittal.

As discussed in Section 3.1, the equipment to be located at the four BSPP power blocks, including the emission sources, have been rearranged. As a result, the source locations were updated in the modeling and a new GEP analysis was performed to determine the effects of downwash due to nearby structures for each emission source. The results of the GEP analysis are shown in Table 3-1. The reconfigured power block is shown in Figure 3-1. Note that the figure shows the power block for one of the two southern solar arrays at BSPP, i.e. Solar Arrays #3 and #4. The power blocks for the northern two arrays are arranged identically except that they are flipped 180 degrees such that the air-cooled condenser structure is on the southern end of the power block for Solar Arrays #1 and #2.

To eliminate the problem of HTF freezing, a gas-fired HTF heater, rated at 35 million British thermal units per hour, was proposed in the AFC for each of the four power Units to ensure that the HTF system temperature would stay above the HTF freezing point of 54 degrees Fahrenheit. Palo Verde Solar I, LLC (PVSI) has decided to eliminate the separate gas-fired HTF heaters and instead use the Project's proposed auxiliary boilers as the source of heat for HTF freeze protection. During the coldest winter nights, each auxiliary boiler, which will typically run at 25 percent capacity overnight to provide steam for the steam seals in the Steam Turbine Generator (STG), will be utilized at 100 percent capacity to provide steam to each of the four HTF heat exchangers. Thus, instead of four fired HTF heaters, the Project will use *unfired heat exchangers* that utilizes steam from the auxiliary boilers as the heating medium.

Based on additional information provided by the Project engineers, PVSI has determined that the wet cooling tower used for heat rejection of the lube oil and generator cooling loops will have to operate 24 hours per day rather than 16 hours per day as was stated in the AFC. PVSI expects that the cooling tower will not operate at full capacity during the additional 8 hours per day; however, emissions are estimated based on full load operation.

Table 3-1: Revised GEP Analysis for BSPP Power Block Sources

Emission Source	Model Source Name	Stack Height (m)	Controlling Buildings or Structures	Building Height (m)	Projected Width (m)	GEP Formula Height (m)
Auxiliary Boiler #1	AUXBOIL1	15.24	Power Unit #1 Air Cooled Condenser	36.58	72.86	91.44
Auxiliary Boiler #2	AUXBOIL2	15.24	Power Unit #2 Air Cooled Condenser	36.58	72.86	91.44
Auxiliary Boiler #3	AUXBOIL3	15.24	Power Unit #3 Air Cooled Condenser	36.58	75.72	91.44
Auxiliary Boiler #4	AUXBOIL4	15.24	Power Unit #4 Air Cooled Condenser	36.58	75.72	91.44
Emergency Generator #1	EMERGEN1	3.05	Power Unit #1 Air Cooled Condenser	36.58	84.27	91.44
Emergency Generator #2	EMERGEN2	3.05	Power Unit #2 Air Cooled Condenser	36.58	85.18	91.44
Emergency Generator #3	EMERGEN3	3.05	Power Unit #3 Air Cooled Condenser	36.58	88.24	91.44
Emergency Generator #4	EMERGEN4	3.05	Power Unit #4 Air Cooled Condenser	36.58	88.24	91.44
Fire-Water Pump #1	FIRPUMP1	3.05	Power Unit #1 Air Cooled Condenser	36.58	96.41	91.44
Fire-Water Pump #2	FIRPUMP2	3.05	Power Unit #2 Air Cooled Condenser	36.58	97.22	91.44
Fire-Water Pump #3	FIRPUMP3	3.05	Treated Water Tank #3	7.32	17.60	18.29
Fire-Water Pump #4	FIRPUMP4	3.05	Treated Water Tank #4	7.32	17.60	18.32
Cooling Tower #1	COOL1_1-COOL2_1	6.84	Power Unit #1 Air Cooled Condenser	36.58	101.18-105.67	91.44
Cooling Tower #2	COOL1_2-COOL2_2	6.84	Power Unit #2 Air Cooled Condenser	36.58	101.56-106.39	91.44
Cooling Tower #3	COOL1_3-COOL2_3	6.84	Power Unit #3 Air Cooled Condenser	36.58	105.61-110.44	91.44
Cooling Tower #4	COOL1_4-COOL2_4	6.84	Power Unit #4 Air Cooled Condenser	36.58	105.22-110.44	91.44

The AFC and subsequent Data Response replies contain inconsistent information regarding the frequency of mirror washing; the project description stated once per week during the winter months and twice per week during the summer months and the air quality analysis was based on washing once per month during the winter and twice per month during the summer. PVSI has confirmed that the information in the project description more accurately reflects the anticipated wash schedule. The emission estimates for mirror washing have been revised to reflect the more frequent wash schedule.

PVSI has developed a more comprehensive understanding of the maintenance inspection requirements for the solar field and has revised the maintenance vehicle mileage and corresponding emission estimates accordingly. Simply put, the maintenance inspection vehicles would travel perpendicular to the solar troughs and piping in the vicinity of the connectors rather than parallel to the troughs and piping. In this way, the travel distance for inspections and corresponding vehicle emissions are reduced substantially compared to initial estimates.

As noted elsewhere, PVSI has decided against using RO concentrate for dust suppression and will direct this wastewater stream to evaporation ponds for disposal. Consequently, water truck use for dust suppression activities using the RO concentrate will not be required, and the emissions associated with this water truck use would not occur. The maintenance vehicle emission estimates have been revised to eliminate the emissions associated with RO concentrate water truck use.

3.2 Impacts from BSPP Operations

The source configurations for the operations modeling remained the same as in the BSPP AFC modeling with the exception of the changes to the ancillary equipment noted in Section 3.2. The worst-case normal operations emissions of the Project ancillary sources were modeled along with vehicular emissions from the solar field maintenance vehicles. Additionally, since an updated cumulative modeling demonstration was also required, and because it was demonstrated in the previous cumulative modeling that nearby non-Project sources like the Blythe Energy Project contribute almost nothing to BSPP cumulative impacts, those off-site sources were included in the updated normal operations modeling.

The maximum-modeled concentrations for all Project emissions are summed with ambient background concentrations for comparison to the NAAQS/CAAQS in Table 3-2. As shown in Table 3-2, the total concentrations comprised of maximum modeled concentration plus maximum ambient background are below the NAAQS/CAAQS for all pollutants with the exception of the 24-hour PM10 CAAQS and NAAQS, annual PM10 CAAQS, and 1-hour NO_2 CAAQS.

In the case of PM10, the ambient background already exceeds the standards and Project contributions are relatively small (45 percent and 14 percent of the 24-hour and annual PM10 CAAQS, respectively).

In the case of 1-hour NO_2, only 2002 showed modeled impacts which, when added to the maximum ambient background, exceeded the 1-hour NO_2 CAAQS of 339 $\mu g/m^3$. The modeled exceedances occur at night under limited dispersion conditions and are principally due to emissions from the emergency generators. However, the emergency generators are unlikely to be tested at night so the modeling analysis is conservative. To refine the modeling analysis, AERMOD was rerun using the “Maxifile” option to determine how many hours produced impacts of at least 164 $\mu g/m^3$, which when added to the maximum ambient background concentration of 175 $\mu g/m^3$, would exceed the CAAQS. The results showed that only 3 hours out of the 3 years modeled (i.e., an average of only 1 hour per year) had the potential to exceed the 1-hour NO_2 CAAQS.

As a further refinement, hourly NO_2 background data for the Palm Springs, California monitoring site were acquired from the EPA AIRS database data repository (http://www.epa.gov/ttn/airs/airsaqs/detaildata/downloadaqsdata.htm). The actual ambient background NO_2 concentration for each hour was then added to the modeled concentration and compared to the CAAQS. The results are shown in Table 3-3. As seen in the table, when added to the time matched ambient background NO_2 concentration, all 3 hours with the potential to exceed the CAAQS fall well below the standard of 339 µg/m^3. As discussed above, the peak 1-hour NO_2 impacts for the BSPP during operations are modeled to occur at night and are caused almost entirely by emissions from the emergency diesel generators. Testing of emergency engines is unlikely to occur during nighttime hours, as simulated in the model for the three potential problem hours. The modeling results presented in Table 3-3 are therefore conservative and demonstrate that the NO_2 CAAQS is unlikely to be exceeded during operations at the BSPP.

Table 3-2: CAAQS/NAAQS Cumulative Modeling Impacts for Normal Operations

Pollutant	Averaging Period	Concentrations (µg/m^3)				
		AERMOD Result	Ambient Background[2]	Total [3]	CAAQS	NAAQS
NO_2 [1]	1-hr CAAQS	168.5	174.9	343.4	339	--
	1-hr NAAQS	178.7	N/A	178.7	--	188
	Annual	0.896	22.6	23.5	57	100
CO	1-hr	267.6	2,645	2,912.6	23,000	40,000
	8-hr	86.5	1,035	1,121.5	10,000	10,000
PM10	24-hr	22.3	162.0	184.3	50	150
	Annual	2.7	30.0	32.7	20	--
PM2.5	24-hr	2.9	27.0	29.9	--	35
	Annual	0.8	10.6	11.4	12	15
SO_2	1-hr	7.4	503.0	510.4	665	--
	3-hr	3.1	434.9	438.0	--	1,300
	24-hr	0.8	99.6	100.3	105	365
	Annual	0.1	5.2	5.3	--	80

[1] Modeled NO_2 concentrations as determined with the OLM. See section 3.5 for discussion of modeling for 1-hour NO_2 NAAQS.

[2] From Table 5.2-33 of the BSPP AFC. These values correspond to the highest monitored values from 2005 – 2007, except for PM2.5, which is the 98th percentile value over three years for the Indio, California monitoring site.

[3] Modeled concentration plus ambient background.

Table 3-3: Time matched NO_2 impacts for Hours with Potential CAAQS Exceedence

Hour	Modeled Impact (µg/m^3)	Ambient Background (ppm)	Ambient Background (µg/m^3)	Total Concentration (µg/m^3)	Fraction of CAAQS (%)
5/04/02 Hour 19	164.81	0.010	18.81	183.62	54%
6/15/02 Hour 23	168.45	0.008	15.05	183.50	54%
6/17/02 Hour 24	165.72	0.012	22.57	188.29	56%

3.3 Modeling of the 1-hour NO_2 NAAQS for Normal Operations

On April 12, 2010, the EPA 1-hour NO_2 NAAQS became effective. Per EPA, the form of the standard is stated as follows:

> “On January 22, 2010, EPA announced a new hourly NO_2 standard of 100 ppb based on the 3-year average of the 98th-percentile of the annual distribution of daily maximum 1-hour concentrations. The final rule for the new hourly NAAQS was published in the Federal Register on February 9, 2010, and will be effective on April 12, 2010”.(http://www.epa.gov/air/nitrogenoxides/actions.html#jan10)

Because the EPA-preferred air dispersion model, AERMOD, does not output results in a format that can be compared to the form of the standard, AECOM has developed an AERMOD post-processor that uses binary output produced by a 1-hour NO_2 AERMOD run and processes the data for comparison to the 1-hour NO_2 NAAQS. The “POST-1HR” postprocessor performs the following steps:

- Using binary output from AERMOD, the hourly impacts for each receptor for each year processed are read in, and the time-matched ambient background concentration for each hour is added to the modeled impact to produce a total concentration at each receptor for each hour.
- Using the hourly data, the highest total impact at each receptor for each day is then determined. This is the “maximum daily impact” referenced in the form of the standard.
- For each receptor, the 98th percentile of the maximum daily impacts is determined for each year modeled.
- Finally, the 98th percentile of the maximum daily impacts is averaged over the 3 years modeled to determine the final concentration for comparison to the standard.

AECOM applied the “POST-1HR” post-processor to the BSPP 1-hour NO_2 modeling for normal operations to demonstrate compliance with the 1-hour NO_2 NAAQS.

As shown in Table 3-2, the 3-year average of the 98th percentile maximum daily 1-hour NO_2 impacts, including BSPP sources, nearby non-Project sources, and ambient background concentrations, is 178.7 µg/m^3. As the the standard is 100 parts per billion (ppb) (188.1 µg/m^3), the cumulative impact of BSPP and other area sources is below the standard, and therefore compliance is demonstrated.

The “POST-1HR” post-processor, along with all files used in the processing, is included in the electronic modeling archive provided in Appendix B of this submittal.

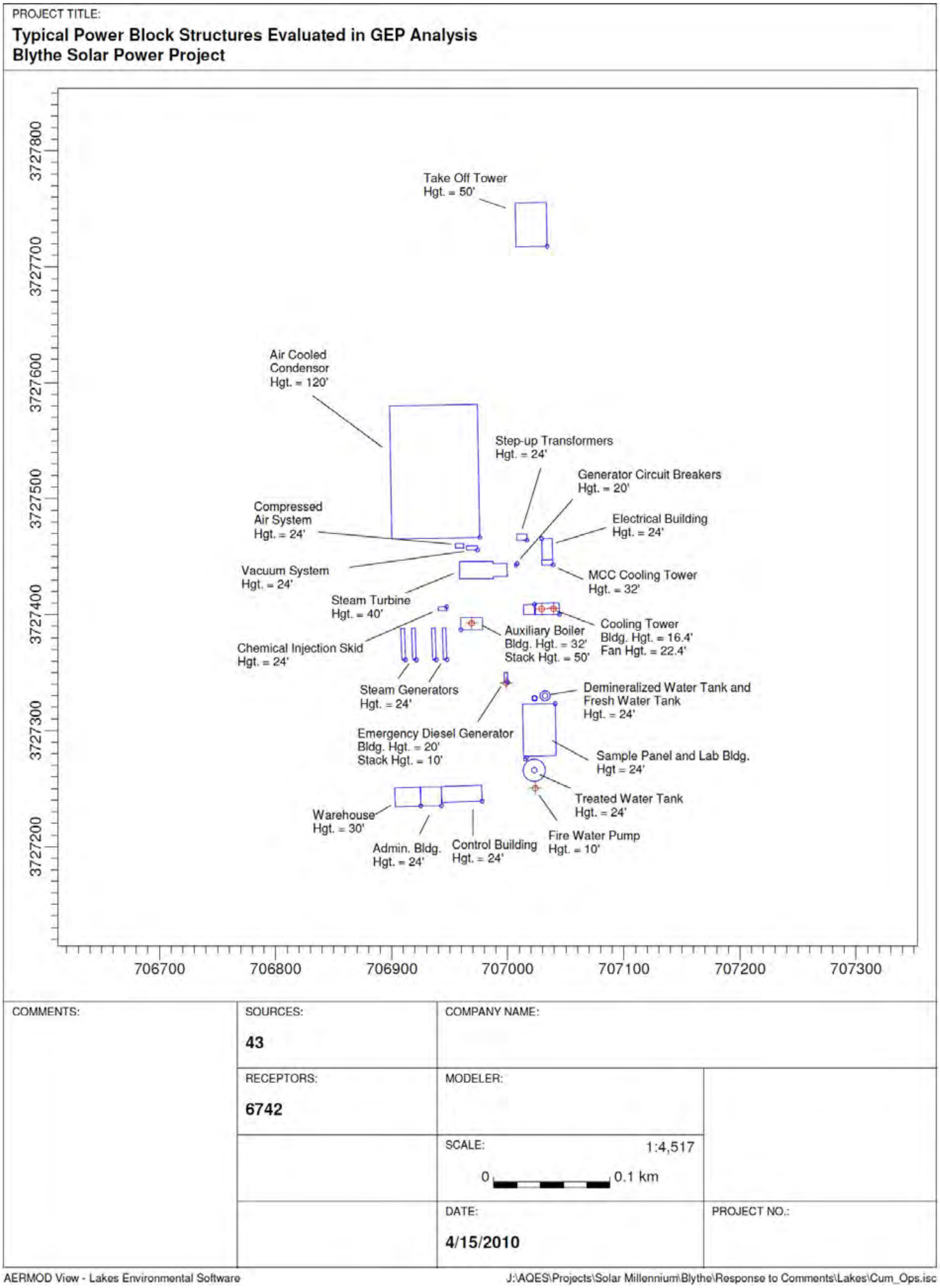

Figure 3-1: Typical Power Block Layout for BSPP Used in GEP Analysis

Appendix B

Air Modeling Files

(See Air Modeling Files on CD)

Appendix C

Batch Plant Emissions

(See Excel File on CD)

Appendix D

Operations Emissions

(See Excel File on CD)

Appendix E

Water Modeling Files

(See Modeling Files on CD)

ATTACHMENT 3

COMMENTS TO PDOC

February 26, 2010

Mr. Elson Heaston
Executive Director
Mojave Desert Air Quality Management District
14306 Park Avenue
Victorville, CA 92392

Subject: Comments on Preliminary Decision/Determination of Compliance for the Blythe Solar Power Project

Dear Mr. Heaston,

On behalf of Palo Verde Solar I, LLC, Solar Millennium, LLC has reviewed the Preliminary Decision/Determinations of Compliance (PDOC) that the Mojave Desert Air Quality Management District (MDAQMD or District) proposes to issue to the Blythe Solar Power Project (BSPP). Overall we are pleased with the first draft of the PDOC and have very few comments. However, we believe that revisions and clarifications are appropriate in several instances.

This correspondence provides specific comments related to the individual sections of the PDOC, arranged using the same section numbering shown in the PDOC. The requested revisions are illustrated using underline format for additional language and ~~strikethrough~~ format for text that should be deleted.

List of Abbreviations

The following acronyms are not used in the PDOC and are not applicable to the BSPP. These acronyms need to be deleted from the acronym list:

- ~~AVAQMD,~~
- ~~CEMS,~~
- ~~CERMS,~~
- ~~CTG,~~
- ~~HDPP,~~
- ~~HRSG,~~
- ~~RSP,~~
- ~~SCAQMD,~~
- ~~SJVAPCD,~~
- ~~SCLA,~~
- ~~SCR,~~ and
- ~~TOG.~~

1.0 Introduction

On January 26, 1010 the Applicant sent a letter responding to request for information to the District. That letter contained an error describing the Applicant and ownership structure. To clarify, Solar Millennium, LLC and Chevron Energy Solutions, originally proposed to construct, own and operate the BSPP as two separate facilities; however, the Applicant is now requesting that CEC issue one license to a project-specific company known as Palo Verde Solar I, LLC (PVSI). PVSI is a wholly owned subsidiary of Solar Millennium and is the single applicant for the BSPP. PVSI will own and operate all four power block units of BSPP; the PDOC should be revised to reflect this change of ownership and operation. CES and Solar Millennium LLC have a development agreement relating to the development of the BSPP. The footer of the PDOC should be modified to reflect this requested change, i.e., the footer should read:

BSPP – PVSI ~~Chevron Energy Solutions~~.

2.0 Project Location

No comments.

3.0 Description of Project

In paragraph 1 of this section (page 1, paragraph 4), the last sentence should be stricken. As noted above, PVSI will own and operate all four solar units of the BSPP. The modified text is shown below:

> The proposed facility will consist of four 250 MW (gross) solar units. The Project uses parabolic trough solar thermal technology to generate electricity. In each power generating unit or power block, the proposed technology uses a steam turbine generator (STG) fed from a solar steam generator (SSG). SSGs receive heat transfer fluid (HTF) from solar thermal equipment comprised of arrays of parabolic mirrors that collect energy from the sun. ~~Chevron will own and operate two power block units and Solar Millennium will own and operate two power block units.~~

In paragraph 4 of this section (page 2, paragraph 5, (the bullet point list of equipment), PVSI will be installing four (4) of each listed devices. In addition, the description for the HTF expansion tanks and ullage system does not accurately convey the equipment that will be installed. For each power block, there will be one ullage system comprised of a number of tanks, pressure vessels, heat exchangers and flash distillation columns; the carbon adsorption system is associated with the ullage system vent. While the ullage system and HTF expansion / overflow tanks are hard-piped together, they are two separate subsystems of the HTF loop. For each power block there will be one HTF expansion tank and multiple HTF overflow tanks. However, under normal operating conditions the expansion tanks and overflow tanks are closed, pressurized vessels, with no emissions to atmosphere, and consequently, do not need to be listed as emissions units on this PDOC. Suggested changes are shown below:

> ~~Chevron Energy Solutions~~ PVSI is proposing to install:
>
> - ~~two (2)~~ four (4) Tier III diesel fueled emergency fire pump engines rated at 300 hp
> - ~~two (2)~~ four (4) Tier II diesel fueled emergency generator set rated at 2,922 hp
> - ~~two (2)~~ four (4) auxiliary natural gas fired boilers each rated at - 35 MMBtu/hr
> - ~~two (2)~~ four (4) HTF natural gas fired heaters for freeze protection each rated at - 35 MMBtu/hr
> - ~~two (2)~~ four (4) HTF ullage systems ~~/expansion tanks~~ with carbon adsorption systems
> - ~~two (2)~~ four (4) cooling towers each with drift eliminator

In the list of equipment specifications that follows paragraph 5 of this section, the number of devices should be changed from 2 to 4 in each case.

4.0 Overall Project Emissions

(Note: The Section header for "Overall Project Emissions" is not shown as Section 4; however, it appears as though it should have been. It is shown as Section 4 herein to maintain the numbering convention for the remainder of the sections.)

On page 4 of the PDOC, MDAQMD states that the Heat Transfer Fluid (HTF) freeze protection heaters have permitted emission limits based on fuel usage; however the permit conditions for the HTF heater do not have limits on fuel usage and instead limit the hours of operation. The sentence starting on line 11 of the Overall Project Emissions paragraph should be changed to reflect the limitations on the hours of operation:

> Project emissions limited by permit condition based on fuel usage for the auxiliary boilers ~~and HTF freeze protection heaters~~ and by hours of operation for the HTF freeze protection heaters and emergency generator and fire pump internal combustion engines.

Maximum Annual Emissions – Table 1

The emissions presented in Table 1 do not match the emissions presented in Appendix A. These emission values should match the numbers presented in Table A-1 of the Appendix and also need to be changed to reflect the operation of all four power block units. Based on the calculations in the Application for Certification (AFC) and the in the letter entitled: "Modifications to the Air Permit Applications for the BSPP," dated January 26, 2010, Table 1 should read:

Table 1 – BSPP ~~Solar Millennium~~ Maximum Annual Operational Emissions				
(All emissions presented in tons per year – ~~two~~ four power block units, VOC fugitive emissions included)				
NOx	**SOx**	**CO**	**PM10**	**VOC**
~~2.155~~ 4.78	~~0.719~~ 0.04	~~3.016~~ 7.48	~~1.745~~ 1.82	~~2.352~~ 4.70

Maximum Daily Emissions – Table 2

The emissions presented in Table 2 do not match the emissions presented in Appendix A. These emission values should also match the number presented in Table A-1 of the Appendix and need to be changed to reflect PVSI's operation of all four power block units. Based on our calculations Table 2 should read:

Table 2 – BSPP ~~Solar Millennium~~ Maximum Daily Operational Emissions				
(All emissions presented in pounds per day– ~~two~~ four power block units, VOC fugitive emissions included)				
NOx	**SOx**	**CO**	**PM10**	**VOC**
~~65.388~~ 149.42	~~18.261~~ 0.74	~~44.763~~ 156.99	~~25.343~~ 28.24	~~20.545~~ 41.11

BACT Thresholds and Project Trigger

The first paragraph of Section 5, Control Technology Evaluation/BACT Determination states that the internal engines have the potential to emit more than 25 pounds per day of NOx. Based on emissions calculations, only the emergency generator engines have the potential to emit more than 25 pounds per day of NOx. The last sentence should read:

> Based on the proposed project's maximum emissions as calculated in §4 above, the project triggers only BACT for the proposed emergency generator ~~internal combustion~~ engines, which have the potential to emit more than 25 pounds per day of NOx.

Proposed Limit for each Carbon Adsorption System (Expansion Tank/Ullage Vent System)

The control efficiency for carbon adsorption presented in the table is unclear. BSPP plans to use a two-stage carbon adsorption system, and each stage provides at least 85 percent control. This yields an overall control efficiency of 98 percent. BSPP did not propose to use a condenser.

Pollutant	Control
VOC	Control adsorption with at least 85% control efficiency for one stage.
NOx, SOx, CO, PM	Not applicable

> The proposed 2 stage ~~condenser/~~carbon adsorption system meets presumptive MACT and provides for 98% control of VOC emissions. VOC emissions from the system will not exceed 1.5 lb/day from each of the four proposed vents.

Proposed Limit for Each Cooling Tower

The PDOC states: "[T]he facility will be required to have a functional hydrocarbon detection device and to repair leaks in a timely manner". A hydrocarbon detector was not proposed by the applicant and use of such a device is not warranted in this situation. Hydrocarbon leaks into a cooling water system may occur in a high pressure heat exchanger, but are not expected to occur in the low pressure exchangers proposed for the Project. Further, should a leak occur, the oil that would enter the cooling water loop has a negligible vapor pressure and is would not volatilize from the cooling tower. Thus a hydrocarbon detector should not be required for the Project, and we request that this statement be removed from the BACT section, as follows:

> The proposed cooling towers will have drift eliminators with vendor-guaranteed PM control efficiency of 0.0005%). ~~The facility will be required to have a functional hydrocarbon detection device and to repair leaks in a timely manner.~~ The proposed cooling towers meet the above requirements.

BACT for each Internal Combustion Engine – Emergency Generator and Fire Pump (Total of eight engines)

Compliance with the NSPS and ATCM is determined to be BACT for the fire pump and emergency generator engines and is found to be an engine meeting the current tier requirements. The proposed engines meet this requirement, but the emissions limits presented in the Table in the PDOC are incorrect for the emergency generator. The emission factors and corresponding emissions calculations need to be revised to reflect the appropriate Tier II standards for the emergency generator engine as shown in the Table below.

Proposed Engine – Fire Pump	NOx + NMHC (g/bhp-hr)	PM (g/bhp-hr)	CO (g/bhp-hr)	SOx
300 hp Tier III	3.0	0.15	2.6	15 ppm S fuel
Proposed Engine – Emergency Generator	**NOx + NMHC (g/bhp-hr)**	**PM (g/bhp-hr)**	**CO (g/bhp-hr)**	**SOx**
2,922 hp Tier II	~~4.0~~ 4.8	~~0.07~~ 0.15	~~0.37~~ 2.6	15 ppm S fuel

6.0 PSD Class I Area Protection

No comments.

7.0 Air Quality Impacts Analysis

No comments.

8.0 Health Risk Assessment and Toxics New Source Review

No comments.

9.0 Offset Requirement

The emissions presented in Table 5 do not match the emissions presented in the PDOC Appendix. These emission values should also match the number presented in Table 1 of the PDOC and need to be changed to reflect the ownership of all four power block units. Based on our calculations Table 5 should read:

Table 5 – Comparison of BSPP Emissions with Offset Thresholds
All emission in tons per year

	NOx	VOC	SOx	PM10
Maximum Annual Potential to Emit	~~2~~ 4.78	~~1~~ 4.70	~~0~~ 0.04	~~4~~ 42.77
Offset Threshold	25	25	25	15

10.0 Applicable Regulations and Compliance Analysis

The rule compliance for rule 1302 needs to be changed to reference the MDAQMD; BSPP is not under the jurisdiction of the Antelope Valley Air Quality Management District (AVAQMD). Please revise the compliance method of Rule 1302 to read:

> "Rule 1302 - Procedure requires certification of compliance with the Federal Clean Air Act, applicable implementation plans, and all applicable ~~AVAQMD~~ MDAQMD rules and regulations."

11.0 Conclusion

No comments.

12.0 Permit Conditions

Each of the subsections within this section has listed the number of devices and application numbers for those devices in italics. In each case, because the PDOC refers to only one-half of the Project, two devices are listed and only two application numbers are listed. When the District combines the Chevron PDOC with the Solar Millennium PDOC into a single PDOC for PVSI, we ask that the number of units changed to four and all four application numbers be listed.

Auxiliary Boilers Authority to Construct Conditions

Condition 4(a)(2) contains a typographical error related to boiler load. Conditions 4(d) and 4(e) present higher emission factors for SOx and PM10 than the emission factors presented in the AFC. The SOx emission estimates should be based on 0.2 grains (gr) of sulfur per 100 standard cubic feet (scf) of natural gas, and the PM10 emissions should be calculated based on a vendor guaranteed emission factor of 0.01 lb/MMBtu. Based on these recommended changes, Condition 4 should be revised as follows:

4. Emissions from this equipment shall not exceed the following hourly emission limits at any firing rate, verified by fuel use and compliance tests:
    a. NOx as NO_2:
        1. 0.389 lb/hr operating at 100% load (based on 9.0 ppmvd corrected to 3% O_2 and averaged over one hour)
        2. 0.097 lb/hr operating at ~~100%~~ 25% load (based on 9.0 ppmvd corrected to 3% O_2 averaged over one hour)
    b. CO:
        1. 1. 1.322 lb/hr operating at 100% load (based on 50 ppmvd corrected to 3% O_2 and averaged over one hour)
        2. 0.331 operating at 25% load (based on 50 ppmvd corrected to 3% O_2 and averaged over one hour)
    c. VOC as CH_4:
        1. 0.175 lb/hr operating at 100% load
        2. 0.044 lb/hr operating at 25% load
    d. SOx as SO_2:
        1. ~~0.183~~ 0.010 lb/hr operating at 100% load
        2. ~~0.046~~ 0.0024 lb/hr operating at 25% load
    e. PM10:
        1. ~~0.700~~ 0.0350 lb/hr operating at 100% load
        2. ~~0.175~~ 0.0875 lb/hr operating at 25% load

Condition 7 requires annual compliance tests for NOx, VOC and CO. An annual test for NOx and CO is understandable, as those pollutants have BACT limits; however, there is no regulatory reason to require annual testing for VOC. VOC has no BACT, rule or offset-driven emission limit. VOC emission estimates are based on commonly accepted emission factors; an annual compliance test would only serve to validate the factor, which should not be the responsibility of the Applicant. High VOC emissions would be an indication of incomplete combustion; however, excess CO is also an indicator of incomplete combustion and, as noted, the applicant has no objection to the CO test. That being said, we do understand and agree that an initial compliance test as required by Condition 8 is appropriate, and recommend that instead of annual VOC emission testing that a VOC compliance test should be required during the initial compliance test only. We request that the requirement for the annual compliance test for VOC be deleted from the Condition 7, and added to the initial compliance test in Condition 8, as shown below:

7. The o/o shall perform annual compliance tests on this equipment in accordance with the MDAQMD Compliance Test Procedural Manual. The test report shall be submitted to the District no later than six weeks prior to the expiration date of this permit. The following compliance tests are required:

a. NOx as NO_2 in ppmvd at 3% oxygen and lb/hr (measured per USEPA Reference Methods 19 and 20).
~~b. VOC as CH_4 in ppmvd at 3% oxygen and lb/hr (measured per USEPA Reference Methods 25A and 18).~~
~~c~~<u>b</u>. CO in ppmvd at 3% oxygen and lb/hr (measured per USEPA Reference Method 10).
~~d~~<u>c</u>. Flue gas flow rate in dscf per minute.

8. The o/o shall perform an initial compliance test on this equipment in accordance with the MDAQMD Compliance Test Procedural Manual within 180 days of initial start up. The test report shall be submitted to the District within 6 weeks of performance of the test. The initial compliance test shall be for all items listed in condition 7 above, in addition to:

a. SOx as SO_2 in ppmvd at 3% oxygen and lb/hr.
b. PM10 in mg/m at 3% oxygen and lb/hr (measured per USEPA Reference Methods 5 and 202 or CARB Method 5).
<u>c. VOC as CH_4 in ppmvd at 3% oxygen and lb/hr (measured per USEPA Reference Methods 25A and 18).</u>
~~c~~<u>d</u>. Opacity (measured per USEPA reference Method 9).

HTF Heater Authority to Construct Conditions

Condition 4 lists hourly emission limits. There appears to be a minor (rounding?) error in the emission rate specified for NOx. The SOx emission estimates should be based on 0.2 grains (gr) of sulfur per 100 standard cubic feet (scf) of natural gas, and the PM10 emissions should be calculated based on a vendor guaranteed emission factor of 0.01 lb/MMBtu. Based on these recommended changes, Condition 4 should be revised as follows:

4. Emissions from this equipment shall not exceed the following hourly emission limits at any firing rate, verified by fuel use and annual compliance tests:
   a. NOx as NO_2 ~~0.391~~ <u>0.389</u> lb/hr (based on 9.0 ppmvd corrected to 3% O_2 and averaged over one hour)
   b. CO 1.322 lb/hr (based on 50 ppmvd corrected to 3% O_2 and averaged over one hour)

c. VOC as CH_4 0.175 lb/hr
d. SOx as SO_2 ~~0.183~~ 0.010 lb/hr
e. PM10 ~~0.700~~ 0.0350 lb/hr

Similar to the source test conditions for the boilers, Condition 7 for the heaters requires annual compliance tests for NOx, VOC and CO. An annual test for NOx and CO is understandable, as those pollutants have BACT limits; however, there is no regulatory reason to require annual testing for VOC. As discussed in relation to the boilers, VOC has no BACT, rule or offset-driven emission limit. VOC emission estimates are based on commonly accepted emission factors; an annual compliance test would only serve to validate the factor. High VOC emissions would be an indication of incomplete combustion; however, excess CO is also an indicator of incomplete combustion and, as noted, the applicant has no objection to the CO test. That being said, we do understand and agree that an initial compliance test as required by Condition 8 is appropriate, and recommend that instead of annual VOC emission testing that a VOC compliance test should be required during the initial compliance test only. We request that the requirement for the annual compliance test for VOC be deleted from the Condition 7, and added to the initial compliance test in Condition 8, as shown below:

7. The o/o shall perform annual compliance tests on this equipment in accordance with the MDAQMD Compliance Test Procedural Manual. The test report shall be submitted to the District no later than six weeks prior to the expiration date of this permit. The following compliance tests are required:

a. NOx as NO2 in ppmvd at 3% oxygen and lb/hr (measured per USEPA Reference Methods 19 and 20).
~~b. VOC as CH4 in ppmvd at 3% oxygen and lb/hr (measured per USEPA Reference Methods 25A and 18).~~
~~c~~b. CO in ppmvd at 3% oxygen and lb/hr (measured per USEPA Reference Method 10).
~~d~~c. Flue gas flow rate in dscf per minute.

8. The O/O shall perform an initial compliance test on this equipment in accordance with the MDAQMD Compliance Test Procedural Manual within 180 days of initial start up. The test report shall be submitted to the District within 6 weeks of performance of the test. The initial compliance test shall be for all items listed in condition 7 above, in addition to:

a. SOx as SO2 in ppmvd at 3% oxygen and lb/hr.
b. PM10 in mg/m at 3% oxygen and lb/hr (measured per USEPA Reference Methods 5 and 202 or CARB Method 5).
c. VOC as CH4 in ppmvd at 3% oxygen and lb/hr (measured per USEPA Reference Methods 25A and 18).
~~c~~d. Opacity (measured per USEPA reference Method 9).

Ullage Vent System Authority to Construct Conditions

As noted elsewhere, the Ullage system and the HTF expansion and overflow tanks are separate and distinct subsystems of the overall HTF loop, and not part of the same subsystem. The HTF expansion tanks and overflow vessels operate daily, separately and independently of the ullage system. Under normal operating conditions the expansion tanks and overflow tanks are closed, pressurized vessels, with no emissions to atmosphere, and consequently, do not need to be listed as emissions units on this PDOC. The ullage system operates periodically, usually only once or twice per week for a short period of time, e.g., two hours. We request that this section of the PDOC be revised as follows to reflect the system design:

(Ullage ~~Vent~~ System) Authority to Construct Conditions

[~~Two~~Four - HTF ullage systems ~~expansion tank~~, Application Number: 0010750 and 0010757]

1. This ~~tank stores~~ system purifies HTF, specifically the condensable fraction of the vapors vented from the HTF expansion tank ~~ullage system~~.

2. This ~~tank~~ system must be properly maintained at all times.

3. This ~~tank~~ system shall be operated at all times with the carbon adsorption system under District permit [To be Determined].

Carbon Adsorption System Authority to Construct Conditions

As noted elsewhere, the Ullage system and the HTF expansion and overflow tanks are separate and distinct subsystems of the overall HTF loop, and not part of the same subsystem. We are requesting that the wording of several conditions assigned to the carbon adsorption system be modified to be consistent with the system design. Note that the conditions that do not require modification are not listed herein. In addition, although the Applicant anticipates that benzene may be emitted from the ullage system vent, a FID or PID monitoring device will not directly determine benzene concentration in the exhaust, and consequently, we ask that Condition 10 be modified to eliminate the requirement to monitor benzene.

2. This carbon adsorption system shall provide 98% control efficiency of VOC emissions vented from the HTF ullage ~~expansion tank~~ system under District Permit [to be determined].

5. This equipment must be in use and operating properly at all times the HTF ullage ~~expansion tank~~ system is venting.

10. Prior to January 31 of each new year, the o/o of this unit shall submit to the District a summary report of ~~all benzene and~~ VOC emissions (as hexane).

Cooling Tower Authority to Construct Conditions

Condition 4 for these emissions units places a limit of 2000 ppmv on the cooling tower blowdown on a "calendar monthly basis". We ask that the condition be reworded to clarify the basis for that requirement as an arithmetic average of all TDS tests conducted during the month, and ask that the basis of measurement be ppmw, not ppmv. The suggested modifications are listed below:

4. The operator shall perform weekly tests of the blow-down water total dissolved solids (TDS). The TDS shall not exceed 2000 ~~ppmv~~ ppmw based on an arithmetic average of all TDS measurements conducted each ~~a~~ calendar month~~ly basis~~. The operator shall maintain a log which contains the date and result of each blow-down water test in TDS ppm, and the resulting mass emission rate. This log shall be maintained on site for a minimum of five (5) years and shall be provided to District personnel on request.

13.0 Appendix – BSPP Emissions Calculations

The Applicant has made several comments that affect the emissions calculations in the Appendix. This section will not show the requested revisions using the ~~strikethrough/~~underline format; the recommended changes to the tables in the Appendix will be summarized and discussed in each section.

Table A-1

Table A-1 needs to be revised to reflect the new ownership of all four units of the BSPP by PVSI.

Table A-2

Several revisions need to be made to the calculations in Table A-2. As discussed in **Section 12** of this letter, the emissions calculations for SOx and PM10 appear to be based on incorrect emission factors. These emission factors should be revised in the calculations.

The Applicant has also identified a spreadsheet error in the daily and annual CO emissions. The CO emissions should be 7.648 lb/day, 2,161.25 lb/yr and 1.081 ton/yr. Please revise Table A-2 accordingly.

Table A-3

As discussed in **Section 12** of this letter, the emissions of SOx and PM10 appear to be based on incorrect emission factors. These emission factors should be revised in the calculations.

Table A-4

As discussed in **Section 5**, the emergency generator engines meet the BACT requirement by using Tier II engines, but the emission factors used the calculations are incorrect. The emission factors and corresponding emergency generator engine emissions need to be revised to reflect the appropriate Tier II standards.

Additionally, the SOx emissions should be changed to reflect the use of ultra-low sulfur diesel. The AP-42 SOx emission factor over-estimates emissions. CARB diesel fuel with 15 ppmw sulfur is required for Project operations; emission estimates should be consistent with that requirement.

Table A-5

The maximum daily PTE of the fire pump engine is incorrectly calculated for 24 hours of operation. The fire pump engine is an emergency engine that will only be used for one hour per week, not to exceed 50 hours per year, for maintenance and testing purposes. The emissions associated with emergency operation are not regulated by the ATCM or the MDAQMD rules and should not be included in calculations to determine facility rule compliance. Table A-5 should be revised to reflect maximum daily emissions from one hour of operation of the fire pump engine. The SOx emissions should also be changed to reflect the use of ultra-low sulfur diesel.

We appreciate your consideration of these comments. If you wish to discuss any of these comments, please contact Russ Kingsley at AECOM at (805)388-3775.

Sincerely,

Alice Harron
Sr. Director, Development and Permitting
harron@solarmillennium.com

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
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APPLICATION FOR CERTIFICATION FOR THE *BLYTHE SOLAR POWER PLANT PROJECT*

Docket No. 09-AFC-6

PROOF OF SERVICE
(Revised 3/3/10)

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*indicates change

DECLARATION OF SERVICE

I, Ashley Y Garner, declare that on April 19, 2010, I served and filed copies of the attached **PALO VERDE SOLAR 1, LLC'S INITIAL COMMENTS ON THE STAFF ASSESSMENT/ DRAFT ENVIRONMENTAL IMPACT STATEMENT** dated April 19, 2010. The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at:
[http://www.energy.ca.gov/sitingcases/solar_millennium_blythe**]**

The document has been sent to both the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit, in the following manner:

(*Check all that Apply*)

FOR SERVICE TO ALL OTHER PARTIES:

__X__ sent electronically to all email addresses on the Proof of Service list;

__X__ by personal delivery or by depositing in the United States mail at with first-class postage thereon fully prepaid and addressed as provided on the Proof of Service list above to those addresses NOT marked "email preferred."

AND

FOR FILING WITH THE ENERGY COMMISSION:

__X__ sending an original paper copy and one electronic copy, mailed and emailed respectively, to the address below (***preferred method***);

OR

____ depositing in the mail an original and 12 paper copies, as follows:

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 09-AFC-7
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
docket@energy.state.ca.us

I declare under penalty of perjury that the foregoing is true and correct.

// Original Signed //

Ashley Y.Garner